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Ocean Water Desalination Program Master Plan (PMP)

Power Supply Plan (PSP)

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1. Introduction

1.1. Objectives

The objective of this Power Supply Plan (PSP) is to define power demand requirements, and subsequently identify and assess a range of power supply alternatives for West basin's proposed Ocean Water Desalination Facility. This memorandum will address the key issues associated with developing power supplies and evaluations criteria for comparing the alternatives. Preferred power supply alternatives, as well as their associated costs, will be presented to assist West Basin with their planning and budgeting activities for a full-scale facility.

2. Power Demands

West Basin Municipal Water District is developing a comprehensive ocean water desalination Program Master Plan that will be utilized by West Basin as the supporting document to plan, permit, design, and construct a full-scale ocean water desalination facility and distribution system within its service area. As a new alternative for water supply the District is developing integration of desalinated ocean water as a portion of the local water supply portfolio. To accomplish this objective, West Basin has directed the ARCADIS project team to evaluate power supply alternatives. This section provides an estimate for the electrical power consumption for the desalination plant.

2.1. Desalination Project Power Demand

The power demand is estimated at approximately 0.6-0.8 MW/MGD. However, with additional efficiency improvements, this can potentially be reduced to 0.5 -0.7 MW/MGD.

Using the above factors, the total power requirement for the local supply option (20 MGD) is estimated at approximately 14 MW, while the total power requirement for the regional supply option (60 MGD) is estimated at approximately 46 MW.

A detailed breakdown of the electrical load for the desalination plant is provided in Conceptual System Design and Program Requirements Report. **Table 1-1** is a summary of expected electrical power requirements for plant operation.

Table 2-1: Estimate for the Desalination Project Power Demand

Process	Capacity, MGD Description	10		20		40		60	
		Operating Pumps	Power kW	Operating Pumps	Power kW	Operation Pumps	Power kW	Operating Pumps	Power kW
2	Feed Water Pump Station	1	300	3	900	7	2,100	10	3,000
3	Arkal Filter Backwash Pumps	0	0	0	0	1	10	2	20
3	Arkal Filter Shock Pumps	0	0	0	0	0	0	2	0
6	AF/UF CIP Pump	0	0	0	0	0	0	1	0
8	MF/UF Filtrate Booster P.S.	1	260	3	780	7	1,820	10	2,600
10	RO Feed P.S. – 1st Pass	2	4,780	4	9,560	8	19,120	12	28,680
12	Energy Recovery Devices	2	(300)	4	(600)	8	(1,200)	12	(1,800)
13	RO Feed P.S. – 2nd Pass	1	110	2	220	4	440	6	660
15	RO CIP Pump	1	40	1	40	1	40	1	40
16	Post-Treatment P.S.	1	60	3	180	7	420	10	600
19	Product Water P.S.	1	300	3	1,560	4	4,480	7	7,840
	Total		5,550		12,640		27,230		41,640
	Misc @10% of Total		555		1,264		2,723		4,164
	Total Load		6,105		13,904		29,953		45,804
	Power use kW/MGD		611		695		749		763

Notes:

1. Energy recovery devices will be in operation when desalination plant is operating.
2. Misc. Power includes power for administration building

2.2. Plant Site Power Demand[1]

Plant site power demand is estimated in Section 5.2 in Ocean Water Desalination Program Master Plan (PMP) Conceptual System Design and Program Requirements Report. As stated in Section 5.2 of the PMP Report, for pumps 400 HP or less, a 480 V supply will be used. For pumps >400 HP, a 4160V load center will have to be installed locally to supply power to the pump.

2.3. Distribution Power Demand

The power required with the distribution/transmission system for the connections to local retailer will be a relatively small requirement. In general the electrical requirement will be for SCADA system, flow meter, instruments, lighting, and valve actuator. The load will be supplied through individually metered SCE local connections at each connection point. Supply will be either 480V or 220 V.

[1] The tables and sections referred in this section are presented in Ocean Water Desalination Program Master Plan (PMP) Conceptual System Design and Program Requirements Report Draft Report submitted to West Basin MWD.

3. Power Supply Considerations

3.1. Power Supply Options

3.1.1. Legal Review of Power Supply Options

West Basin conducted a review of the legal aspects of the power supply options for the proposed power demand scenario. The four options that underwent this review are summarized here:

1. Electric service provided directly by SCE
2. Service from an Energy Service Provider ("ESP") under California's Direct Access program
3. Direct purchase from NRG (El Segundo) or AES (Redondo Beach) under Public Utilities Code Section 218
4. Self-generation, joint venture, or other arrangement with a third-party independent power producer ("IPP"), pursuant to Water Code Section 71663.5

Under the state and federal regulatory provisions, of the four supplier options, it appears that only two - SCE service and self-generation - are viable options for West Basin at this time. These options were evaluated for the two selected sites, AES's RBGS and NRG's ESGS. The summary of options evaluated from a legal perspective is listed here.

Option 1: Service from SCE

Three possibilities for SCE service **–**

A. SCE service at the 66KV voltage (transmission level service), B. service under a special "desalination plant" rate; and C. service using SCE's Economic Development Rate. Only the first of these options is available to West Basin.

A. SCE can provide service to the Project at SCE's transmission level voltage (66kV) rate tariff. Further investigation by SCE will be necessary to determine whether the 66kV option could be provided by SCE as standard service or whether West Basin would incur additional costs to qualify for the service. This service will have no legal barriers, since SCE itself has said the tariff can be used.

B. SCE service - Subsidized "Desalination Plant Service" Rate: The California Public Utilities Commission ("CPUC") regulates the terms and conditions under which SCE and other investor-owned utilities ("IOUs") offer retail service, including the rates for electric service. In 2005, the CPUC staff examined whether to recommend

CPUC adoption of subsidized rates for desalination projects. The report noted that the CPUC generally has deferred to the Legislature to determine whether and how much a rate subsidy should be given. While not stating absolutely that the CPUC could not administratively require IOUs to offer a subsidized rate, the staff report stated that providing a discount would have an inevitable corresponding increase of rates for other customers and that, given the "uncertain" benefits (in the staff's view), the rate could run afoul of the CPUC's responsibility to set electrical rates that are just and reasonable.

C. SCE's Economic Development Rate ("EDR"). SCE offers a special EDR to business customers of up to a 12% discount for a five year period. In order to be eligible for the discount, an applicant must sign an affidavit attesting that "but for" the discount, either on its own or in combination with a package of incentives made available to the customer from other sources, "the customer would not have located operations or added load within the state of California. In addition to these issues, EDR is not available to "local government customers."

SCE representative confirmed that public agencies are ineligible

Option 2: Service from an Energy Service Provider ("ESP") Under California's Direct Access Program

The second option is West Basin purchasing power for the desalination plant from an Energy Service Provider ("ESP") under California's Direct Access program. Unfortunately, SCE has closed the program to new participants and it is unclear whether this option will become available in the future.

Option 3: Direct purchase from NRG (El Segundo) or AES (Redondo Beach) under Public Utilities Code Section 218

The direct purchase of power from a non-IOU independent power producer ("IPP") using the provisions of Public Utilities Code section 218. While theoretically this option might exist, in reality it does not. Because the El Segundo and Redondo Beach power plants use natural gas as their fuel, NRG and AES would no longer be exempt from CPUC regulation if they sold power to West Basin from those power plants, since the fuel used at those plants (natural gas) does not qualify under the exemption from CPUC regulation allowed by section 218. AES, NRG and other IPPs operate under a business model outside of CPUC jurisdiction. By being exempt from CPUC jurisdiction they are not subject to the CPUC's rate and service regulation. IPPs will not enter into sales that could make them subject to the agency's oversight, much less dictate the terms under which they sell power.

Under California Public Utilities Code Section 218(b), a power plant owner may use electricity on-site for its own use and it may sell excess electricity directly to an adjacent property without becoming an “electrical corporation”. This provision is known as the “over-the-fence” law, because it allows sales to electric loads on property immediately adjacent to the power plant property. This exemption matters because under Public Utilities Code section 216(a) electrical corporations are “public utilities” subject to the jurisdiction, control, and regulation of the CPUC. Thus, this exemption allows generators to sell excess power to loads on adjacent properties to their power plants, without becoming utilities subject to CPUC jurisdiction.

The section 218 exemption is limited. It only covers sales from “non-conventional” power plants. Both the Redondo Beach plant and the El Segundo plant generate electricity by the use of natural gas. Therefore, these plants will not be eligible for the over-the-fence exemption and could not sell power to a desalination project located adjacent to the plants without being subject to CPUC jurisdiction. In addition, IOUs, such as SCE, have exclusive franchises to operate as public utilities in their service area and would vigorously oppose any attempt by an IPP to encroach on that franchise. Thus, section 218 does not allow the option of a direct sale from AES or NRG to West Basin for a desalination plant located adjacent to the El Segundo or Redondo Beach power plants.

Option 4: Self-generation, joint venture or other arrangement using Water Code Section 71663.5

The option of self-generation using Water Code 71663.5 option is legally available to West Basin under the state and federal energy regulatory framework and offers considerable flexibility in developing a power supply for the desalination project, via either self-generation done alone by West Basin or in a joint venture or other arrangement with NRG or AES. The later could allow West Basin potentially significant opportunities to minimize risks and maximize economic benefits.

Conclusion

Based on WB Legal Service review, the two feasible supplies of power for West Basin’s proposed desalination plant are service from SCE and development of a power supply relying upon the authority provided to West Basin in Section 71663.5. The latter appears to be a matter of first impression and will require further analysis to analyze the economics of this option as well as structures that best comply with state and federal energy laws and provide the maximum economic benefit and lowest risk to West Basin.

3.1.2. Technical Evaluation of Various Power Supply Options

The three power supply options considered are:

1. Onsite power generation with conventional means
2. Onsite power generation by renewable resources
3. Power supply directly purchased from SCE

Following is the technical analysis of these three power supply options.

3.2. Onsite Power Generation Options

The California Public Utilities Commission’s (CPUC) Self-Generation Incentive Program (SGIP) provides incentives to support existing, new, and emerging distributed energy resources. The SGIP provides rebates for qualifying distributed energy systems installed on the customer's side of the utility meter. Qualifying technologies include wind turbines, fuel cells, and corresponding energy storage systems. The SGIP was established in 2001 as a peak-load reduction program seeking to encourage the development and commercialization of new distributed generation (generation installed on the customer's side of the utility meter). Incentive payments to SGIP participants benefit all ratepayers by reducing the need for utilities to invest in expensive transmission and distribution infrastructure. Senate Bill 412, also extends the SGIP from January 1, 2012, to January 1, 2016.

The program is available to customers of Pacific Gas and Electric Company, Southern California Edison, Southern California Gas Company, and San Diego Gas & Electric.

The SGIP was created by the CPUC to offer financial incentives to customers who install certain types of distributed generation facilities to meet all or a portion of their energy needs. Self-generation benefits both the local utility and its customers by reducing electrical system demand, which in turn reduces the need to build expensive fossil fuel-fired power plants. SGIP functions by providing one-time upfront incentives for the installation of new, qualifying self-generation equipment installed to meet all or a portion of the electric needs of a facility.

Effective September 2011, the eligibility for participation in the SGIP will be based on greenhouse gas (GHG) emissions reductions. Technologies that achieve reductions of GHG emissions will be eligible for the program, including wind turbines, fuel cells, organic Rankine cycle/waste heat capture, pressure reduction turbines, advanced energy storage, and combined heat and power gas turbines, micro-turbines, and internal combustion engines.

Participants will receive up-front and performance-based incentives (PBI). The incentives will apply only to the portion of the generation that serves a project's on-site electric load.

SCE Program

SCE's SGIP provides financial incentives for the installation of new, qualifying customer self-generation equipment for their own on-site usage. Technologies currently eligible for SGIP incentives are wind and fuel cell generation. Incentives are also provided for advanced energy storage when coupled with an eligible self-generation technology.

The SGIP program is designed primarily with business and large institutional customers in mind.

Rebates for renewable generation—such as wind turbines or fuel cell—that generate less than 30 kilowatts of energy are available through the California Energy Commission's Emerging Renewables Program (ERP). Fuel cells of any size using non-renewable fuels may receive incentives under the SGIP program.

Solar rebates are currently administered under SCE's California Solar Initiative program.

3.2.1. Conventional Power Supply

SGIP program participants are eligible to receive incentives under this program for installing self-generation technologies. Only commercially available and factory new equipment are eligible for incentives, which are based on system type, size, fuel source and out-of-pocket costs. Rebuilt or refurbished equipment is not eligible to receive incentives under this program. The maximum system size is 5 megawatts (MW), although the incentive payment for 2011 was capped at 3 MW and SCE has continued the program for 2012 at the 2011 level.

Eligible generation equipment must be certified to operate in parallel with the electric system grid (not back-up generation) and meet eligibility and GHG emission criteria established by the California Public Utilities Commission (CPUC)[2].

SCE Incentive Program for Self Generation

The CPUC has authorized eligible wind turbine, fuel cells, and combined heat and power (CHP) systems to receive incentives for up to 3 MW of capacity from prior years' carryover funding for 2008 and 2009 and is carried over into 2012. As part of the CPUC decision, incentives for systems larger than 1 MW up to 3 MW will be paid a tiered incentive. SCE Incentives for systems >1 MW are summarized in **Tables 2-1 and 2-2**.

[2] See SGIP Handbook - http://www.cpuc.ca.gov/NR/rdonlyres/5F55B951-9152-4FAE-84BB-0854688472F9/0/SGIPHandbook2011v9.pdf

Table 3-1: SCE Incentives for the Installation of Qualifying Equipment

Incentive Levels[1]	Eligible Technology	Incentive ($/watt)[2]	Minimum System Size[3]
Level 2 Renewable	Wind Turbines	$1.50	30 kW
	Fuel Cells (Renewable fuel)	$4.50	30 kW
Level 3 Non-Renewable	Fuel Cells (Nonrenewable fuel)[4]	$2.50	None
Advanced Energy Storage[5]	Advanced Energy Storage	$2.00	Capped at DG Systems Size

Notes:

1. Level 1 previously included solar generation, now administered through the California Solar Initiative. www.gosolarcalifornia.ca.gov.
2. An additional incentive of 20% will be provided for the installation of eligible Distributed Generation (DG) technologies from a California supplier
3. Maximum incentive payout capped at 3 MW and maximum system size is 5 MW
4. Systems must utilize waste heat recovery meeting Public Utilities Code 216.6
5. Advanced energy storage must be coupled with a wind or fuel cell system to qualify for incentives

The incentives are adjusted to account for the size of the project as per **Table 2-2**.

Table 3-2: Tiered Incentive Rate for Projects up to 3 MW

Capacity	Incentive Rate as % of base in Table 2-1
0 - 1 MW	100%
>1 MW - 2 MW	50%
>2 MW - 3 MW	25%

Conventional Onsite Generation

One option considered for onsite generation is a small combined cycle (CC) plant with gas turbine and steam turbine generator in a combined cycle mode. The gas turbine is fired with pipeline natural gas already available at both NRG and AES sites. The hot exhaust from the gas turbine is directed to a heat recovery steam generator where high pressure steam is generated. The high pressure steam is run through a steam turbine generator to generate additional power.

The gas turbines are available in standard size from many vendors. These gas turbines are available in ~ 1 MW range to 180+MW. The proposed new NRG combined cycle plant will be utilizing two 180 MW gas turbine generators. However, for the proposed desalination facility, the actual power required will be in the range of 15 MW to 40 MW range, based on desalination plant capacity. A power plant in the size > 50 MW will require a detailed review and evaluation by California Energy Commission (CEC). This is an exhaustive process, subject to public hearing and review. Only standard combined cycle configurations offered by vendors in the range of 2.5 MW to 24 MW were reviewed. Other power generation options are available, such as gas reciprocating engines, and may be feasible depending on size and power supply framework utilized.

Power plant configuration

Table 2-3 lists some of the possible on-site combined cycle generation configuration in the range of 2.5 – 24 MW.

Table 3-3: Possible Power Plant Configuration

Model	GT Power	ST Power	Net CC Output
	kW	kW	kW
Dresser Rand KG2-3E	1,895	682	2,526
Pratt & Whitney ST40	4,039	1,454	5,383
Mercury50	4,600	1,656	6,131
Taurus 60	5,670	2,041	7,557
Taurus 65	6,300	2,268	8,397
Rolls Royce 501-KH5	6,447	2,321	8,593
Taurus70	7,520	2,707	10,023
Mars 100	10,430	3,755	13,901
Siemens SGT-400	12,900	4,644	17,193
Titan 130	15,000	5,400	19,992
GE LM2000 PJ	17,657	6,816	23,911
GE LMS2000PS	17,657	6,357	23,533

Figure 2-1 show typical combined cycle configuration – gas turbine, heat recovery steam generator (HRSG), exhaust stack, steam turbine generator, steam condenser, and feed water pump, etc. The vendors offering these configurations include – GE, Siemens, Dresser Rand, Solar Turbine (a division of Cater Pillar), and Rolls Royce. There are other GT manufacturers including ALSTOM, Mitsubishi, and Hitachi; however, they offer only large frame machines with size ranging from 80+ MW. These GT are too large for the application for West Basin desalination plant and are not evaluated here. The steam turbines are custom designed and can be ordered in the size desirable for the application.

Typical footprint and a possible suggested plant layout is shown in **Figure 2-2**. The electrical single line for onsite generation is also included in **Appendix 2:C**.

The cost estimate for different combined cycle plant offered by different vendors is provided in Section 5 Cost Estimates.

Figure 3-1: Typical Combined Cycle Schematic

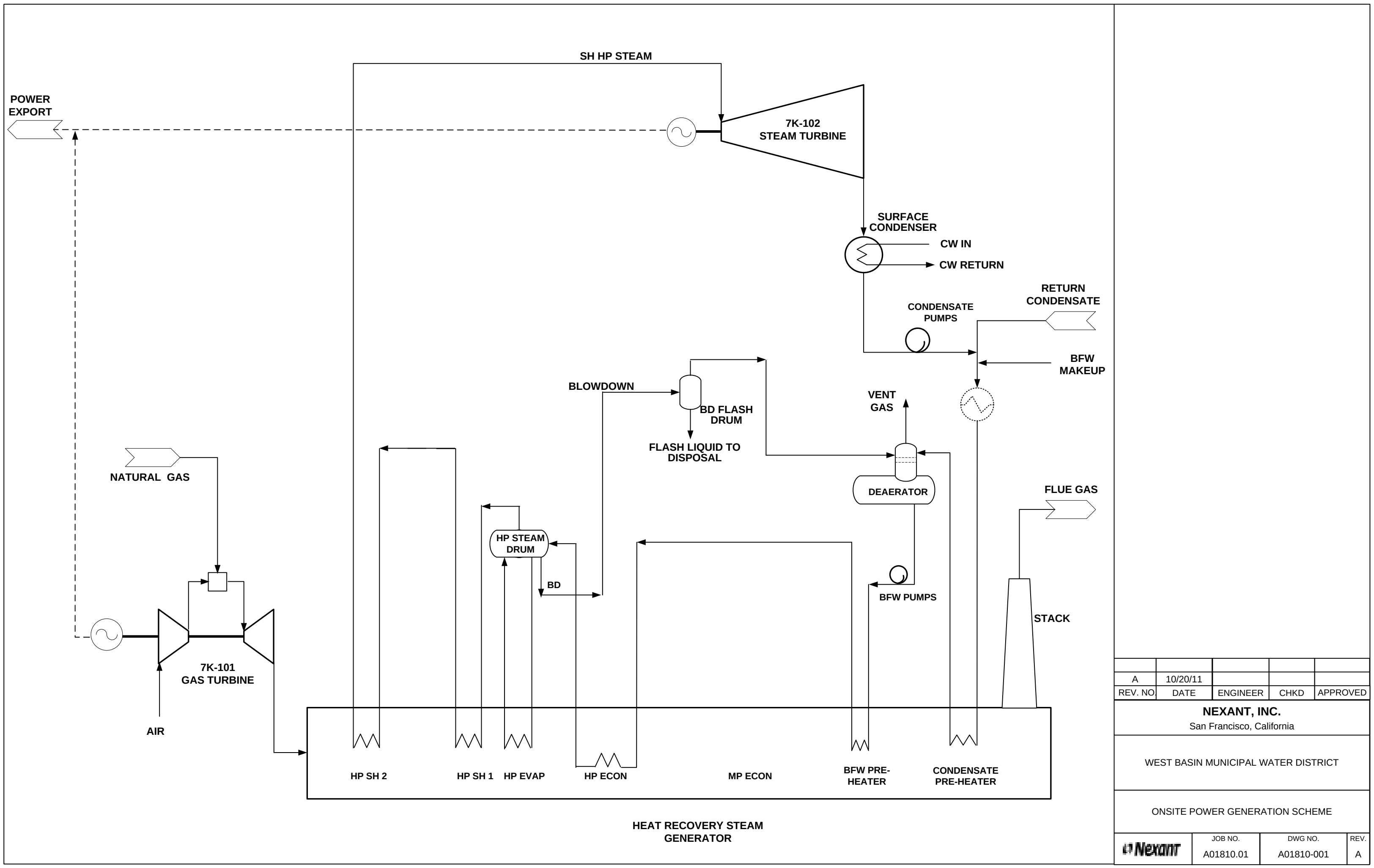
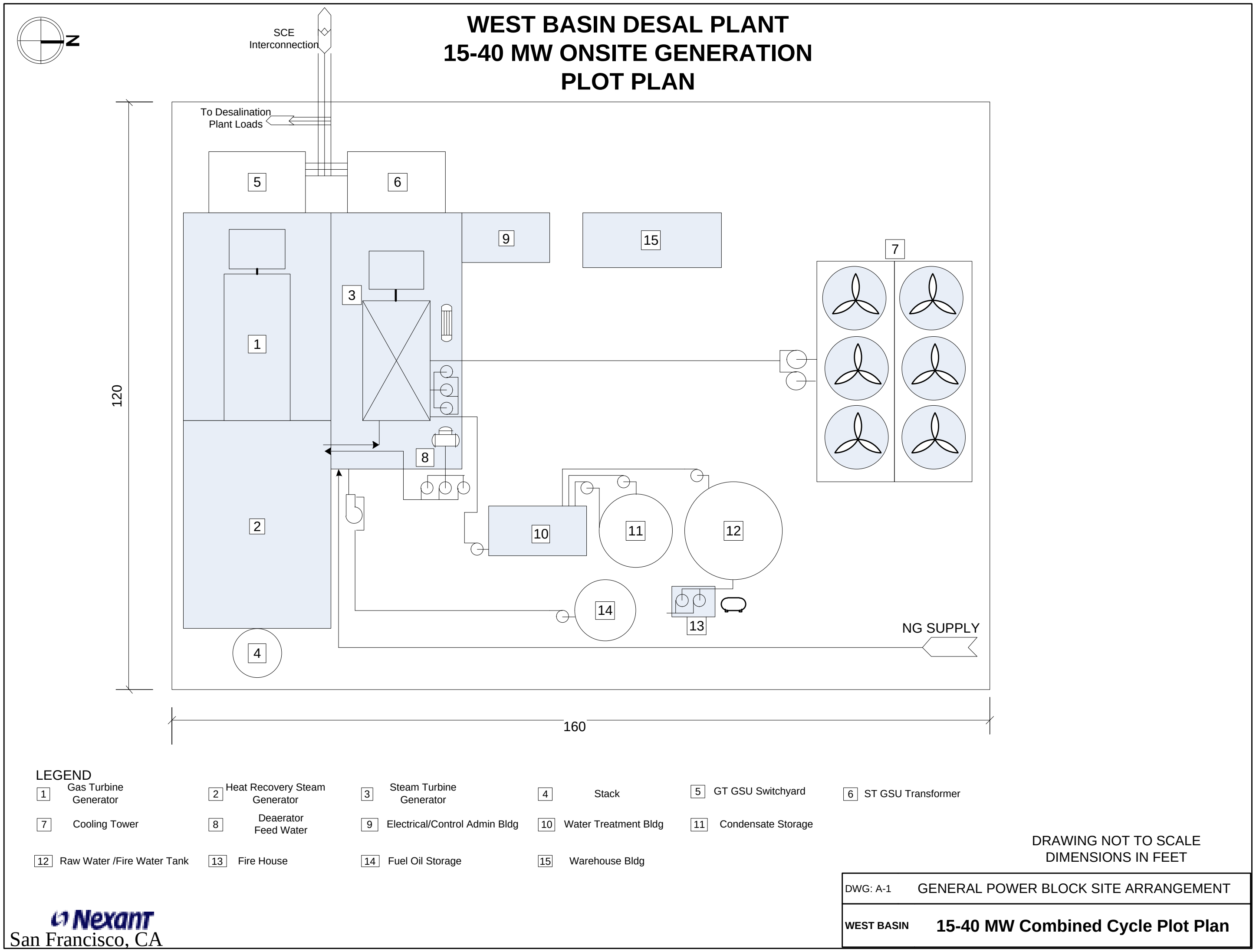


Figure 3-2: Typical Layout and Footprint for Combined Cycle Plan



Under local power supply options scenario with conventional onsite power generation, there will be no renewable credits and no carbon offsets considered.

3.2.2. Renewable Power Supply and Fuel Cell Option

Under renewable power generation, wind, solar, qualifying biomass, geothermal, and small hydro are eligible. However, biomass, geothermal, and small hydro are not feasible at the two proposed sites, so only feasibility of wind and solar is examined. We also evaluated fuel cells. Under California Public Utilities Commission (CPUC) rules, on site fuel cell installation is eligible for incentive from SCE.

Wind Power

Based on California Energy Commission's ("CEC") California Wind Resources Report (April 2005), approximately 4 acres are needed for each 1 MW of wind capacity. The basis for the acreage per MW is numerous, including the type of terrain at a potential site and the size and type of proposed wind turbines. However, at a fundamental level there is a logistical limitation for how many wind turbines can be located at a given site due to the sheer size of the individual units and also to avoid affecting other wind turbines located nearby.

The largest land-based wind turbines are approximately 3.5 MW in capacity and have blade spans of approximately 328 feet. Due to the limited space at the two plant sites it is likely that only one or two large wind turbines could be logistically sited at these sites for a maximum of 3.5 to 7 MW of capacity. Even then, the wind resource maps in the CEC report shows that these two sites are not in locations that could support wind turbines due to the insufficient wind speeds in the area. Therefore, for the reasons described above, wind generation potential at either site is not considered a viable alternative.

Fuel Cells

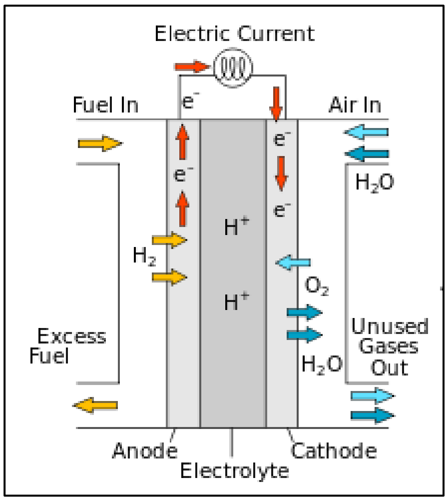
A fuel cell is a device that converts the chemical energy from a fuel into electricity through a chemical reaction with oxygen or another oxidizing agent. Hydrogen is the most common fuel, but hydrocarbons such as natural gas and alcohols like methanol are sometimes used. Fuel cells are different from batteries in that they require a constant source of fuel and oxygen to run, but they can produce electricity continually for as long as these fuel and oxidant inputs are supplied.

Fuel cells are used for primary and backup power for commercial, industrial and residential buildings and in remote or inaccessible areas with no transmission or grid power.

There are many types of fuel cells, but they all consist of an anode (negative side), a cathode (positive side) and an electrolyte that allows charges to move between the two sides of the fuel cell. Electrons are drawn from the anode to the cathode through an external circuit, producing direct current electricity. As the main difference among fuel cell types is the electrolyte, fuel cells are classified by the type of electrolyte they use. Fuel cells come in a variety of sizes. Individual fuel cells produce very small amounts of electricity, about 0.7 volts, so cells are "stacked", or placed in series or parallel circuits, to increase the voltage and current output to meet an application's power generation requirements. In addition to electricity, fuel cells produce water, heat and, depending on the fuel source, very small amounts of nitrogen dioxide and other emissions. The energy efficiency of a fuel cell is generally between 40-60%, or up to 85% efficient if waste heat is captured for use.

Figure 2-3 is a schematic representation of hydrogen fuel cell.

Figure 3-3: Schematic Representation of Hydrogen Fuel Cell



Solar Power

The CEC California Solar Resources Report (April 2005) clearly shows that the various available solar generation technologies would not be viable at these two sites for multiple reasons. The technical potential for concentrated solar power (CSP) in California is limited to areas of sufficient solar resources. On average, the physical space needed for each MW of CSP capacity is 3-5 acres. The CEC and NREL solar insolation data shows that the coastal California is not in a solar resource area that is recommended for CSP technology. The solar resource maps clearly show CSP technology to be best applied in the inland southwest region where significant solar radiation occurs throughout the year. Therefore, solar power generation is not thought to be economically viable in the coastal zone.

For all of these reasons, solar generation on large scale is not a viable alternative at either of the two sites being evaluated for the desalination project. However, roof top PV panels for admin and process buildings are feasible. Although detailed design and layout of these buildings is not developed, based on current design and sizes of PV panels, about 120 -150 square feet of roof area will be required per kW of peak power (11-14 m^2/kW).

It will be feasible to install PV panels on office, administrative building, RO and chemical treatment buildings, operation and maintenance buildings. Total available roof top area will depend on building layouts. For analysis purpose, we assume about 12,000 square feet of roof top area or 100 kW of PV system will be available on individual building. **Table 2-4** is summary of 100 kW DC PV system.

Table 3-4: PV System Design Analysis

Plant Location	Los Angeles /Long Beach CA
Plant Size, kW DC	100
Panel (Module) Size W DC	250
No. of Modules	400
PV Panel efficiency	17.3%
Area/Panel m2	1.95
Area required m2	780
Area required square feet	8,392
Roof Top Area Available square feet	12,000
PV Panel Area/Roof Area	70%
Plant AC Output kW AC	84.265
Plant Capacity Factor (Calculated)	17.10%
Annual Output, kWh	126,226
Estimated Cost $/W	4.9
Total Install Cost, $	490,000
Estimated LCOE $/kWh (no incentives)	$0.124

The 100 kW DC system outlined here is for illustrative purpose, but can be scaled up or down based on available roof area available.

For comparison, a 10 MGD facility will require about 6,100 kW of power. It the facility operates at 90% capacity factor, the annual energy requirement for the facility will be 48+ million kWh. The 100 kW roof top PV will provide 126,226 kWh of energy, or about 0.3% of the total power need. A scale up of 100 kW system to 1 MW system with 100,000 – 120,000 square feet of roof area, it will provide <5% of the energy need for the 10 MGD desalination plant.

3.3. Permitting Requirements for Self Generation

The regulatory permits required to construct on site power generation facility for the desalination plant will have to be prepared in conjunction with the desalination project. The Project Permitting Plan (PPP)[3] developed separately for the desalination plant addresses the key regulatory permits that will need to be obtained by West Basin and MWD in order to complete the desalination project. In the PPP document, critical issues for each permit are identified, along with additional data and studies needed in order to prepare the permit. Content for permit applications and suggestions to negotiate favorable permit provisions and conditions are also discussed. Finally, this plan will also define the scope and budget for the implementation of the engineering support studies needed for project permitting. This plan broadly discusses but does not focus on general construction permits that would be needed. Discussions with lead and supporting Agencies will be critical to refining the information presented in the PPP and honing in on which of the discretionary studies will truly be needed.

For the onsite power generation California Energy Commission (CEC) is responsible entity to permit all power projects >50 MW. Since WB desalination plant power plant will be in the range of 10-30 MW, the permitting requirements fall on the local jurisdiction referred to as Authority of Jurisdiction –AOJ.

Under a self- generation plan, Owner/Operator of the generating facility will be required to obtain:

1. Interconnection agreement with SCE (Island operation without SCE connection is not practical. Redundancy requirements for reliable power under island operation will be cost prohibitive)

2. County/City permit or AOJ to construct a new facility

3. Stationary source air emission permit from South Coast Air Quality Management District (SCAQMD)

There is no comprehensive list of documents required by various city, county, or air quality management district. Based on CEC review process, it is expected that the local

[3] Permitting Plan Technical Memorandum (TM), Draft Project Permitting Plan (PPP) by Arcadis, March 2011; and Project Entitlements Acquisition Plan (PEAP) for Ocean Water Desalination Program Management Plan (PMP), March 2011.

AOJ will also require following technical documents for compliance with typical laws, ordinances, regulations, and standards:

Air Quality, Public Health, Worker Safety, Fire Protection, Transmission Line Safety and Nuisance, Hazardous Materials Management, Waste Management, Land Use, Traffic and Transportation, Noise, Visual Resources, Cultural Resources, Socioeconomics, Biological Resources, Soil & Water Resources, Geological and Paleontological Resources, Power Plant Efficiency, and Transmission System Engineering, if applicable.

A brief description of SCAQMD requirement and process for the permit is described here.

SCAQMD is the air pollution control agency for all of Orange County and the urban portions of Los Angeles, Riverside and San Bernardino counties.

- **Background on AQMD's Permitting Program**
  The AQMD's permitting program has been established to implement the requirements of the federal and state Clean Air Act (CAA), the Air Quality Management Plan (AQMP) and air quality rules and regulations by specifying operating and compliance requirements for stationary sources that emit air contaminants. In order to comply with federal and state CAA requirements, all major and non-major sources in South Coast Air Basin (SOCAB) are subject to "no net emission increase" and Best Available Control Technology (BACT) and/or Lowest Achievable Emission Rates (LAER) for stationary sources-specific, prohibitory and toxics rules (federal, state and local) as well as other applicable requirements.

- **Permit Required from AQMD for WBMWD Self Generation Project**
  The applications to be filed at AQMD are for Permit to Construct (PC) and or Permit to Operate (PO). Prior to installation of new or relocated equipment, or prior to modification of an existing equipment, the operator of the equipment is required to obtain a PC from the AQMD. Once a piece of equipment is installed, modified and/or operated, AQMD processes the application for a PO. In cases where equipment is installed without a prior PC, the AQMD also processes the application directly for a PO. In cases of off the shelf type equipment, the AQMD issues a one-step PC/PO.

- **Types of Permit Applications for WBMWD Project**

  - ***Permit to Construct (P/C)*** - for a new or relocated equipment as well as alteration (both physical modification and change of operating conditions) of existing equipment. These applications always receive a high priority for processing.

- ***Permit to Operate (P/O)*** - for equipment that is installed and/or is operated with or without a prior P/C (a prior P/C or in cases where no prior P/C was issued, the application acts as a temporary P/O until a final P/O is processed).

- **Permitting Program**

  All applications for permit to construct and Permit to Operate are evaluated for compliance with the prohibitory rules, one or more source specific rules, new source review rules for criteria and toxic air contaminants and other applicable rules and regulations.

  In addition, all applications have to meet the requirements for Public Notice, if applicable. Public notices are required for facilities that have risks or emissions that exceed the specified thresholds or for equipment located within 1,000 feet of a school. All such public notices are distributed to the communities near the project and parents of children attending nearby schools and are subject to a 30-day public comment period.

  For Title V permits, public notices are required for Initial Title V permits, Renewals (5 years) and Revisions. For Tile V permits, in addition to the 30-day public comment period, there is also a requirement for a 45-day review period by EPA. Title V permits can only be issued after the public notice period is concluded and after taking into consideration any comments received during the public and EPA comment periods.

Emission permit from SCAQMD will be a challenge, as it will require West Basin to obtain emission credits that are higher than 1:1 (e.g. for NOx SCAQMD required 1.2:1 credit). Although credits are available in the market, there is no established trading system. Without emission offsetting credits, SCAQMD will not grant permit to construct a power generation facility of any size in the SOCAB (emergency backup power is exempt, but restricted to <200 hrs/year). Once emission credits are obtained, it will require filing for application, public hearing period, and final approval that can take over one year.

All units with a potential to emit greater than 25 pounds per day of a criteria pollutant will be required to apply district BACT. The SCAQMD follows CARB's guidance for permitting of electric generating technologies. For control of NOx from turbines and internal combustion engines following are the limit[4]:

[4] http://www.eea-inc.com/rrdb/DGRegProject/States/California/SCAQMD.html

For 3-50 MW combined cycle units the NOx limit is <5 ppm.

Sources with potential emissions of 120 pounds per day or greater are required to complete air quality modeling.

- **Permitting Time Line:**

SCAQMD permitting and obtaining offsets will require maximum time. SCAQMD will inform applicant about all regulatory and technical data adequacy within 30-45 days. Once all necessary data are received the review process can take six months to one year. This is subject to WB obtaining necessary emissions offsets, and public hearing outcome.

3.4. SCE Retail Power Supply Option

The power demand per **Table 1-1** is estimated at 6.1 MW for 10 MGD plant and 45.8 MW for 60 MGD Plant. The SCE supply option analysis is based on power demand of <50 MW. Various loads for the desalination plant will require voltage from 120-480 to 4160 V and for very large motors to run at 11-13 kV range. Based on this power demand, the two proposed sites were evaluated for SCE retail power. A brief description of the two sites is provided here.

3.4.1. NRG Segundo Generating Station

ESGS has been operating as an electric generating station since May 1955. The facility was comprised of four gas-fired conventional, electric power generating units. Units 1 and 2 have been demolished at the site and construction of a combined cycle power plant within the footprint of the demolished units is in progress by the current owner NRG. The current operating capacity of Unit 3 and 4 at El Segundo Power Plant is 670MW. Units 3-4 are used infrequently, with reported capacity factor for combined units 3 and 4 was 10.5% in 2006. The annual capacity factors for unit 3 and 4 in 2011 were 2.7 and 3.4% respectively[5].

The new combined cycle unit will consist of two combustion gas turbine generators (CTGs), two heat recovery steam generators (HRSGs), and one steam turbine generator (STG). Total output of the combined cycle plant will be 550 MW. Heat rejection from the STG will be accomplished with an air cooled condenser, thus eliminating the once through ocean water cooling. Natural gas will be the fuel utilized by the two new CTGs. **Table 2-5** is summary of new configuration for the NRG El Segundo power plant.

[5] CEC Plant G0195 (El Segundo) annual Statistics

Table 3-5: NRG Segundo Power Plant

Unit	In Year Service	Rated Capacity (MW)	Cooling Water Flow[6] (gpm)
Unit 3	1964	335	132,400
Unit 4	1965	335	131,000
GT 1	2013	185	-
GT 2	2013	185	-
STG	2013	180	Air Cooled
ESPS total		1,220	263,400

Figure 2-4 is site layout showing the existing operating units 3 and 4 and proposed location for new combined cycle units under construction and the existing SCE electrical switchyard.

Figure 3-4: NRG ESGS Site Layout

Electricity generated by the El Segundo Power Redevelopment Project will be delivered to the existing Southern California Edison (SCE) substation located on a separate parcel

[6] Tetra Tech Report – California Coastal Power Plants, Alternative Cooling System Analysis NRG ESGS

immediately adjacent to the ESGS property. From SCE's El Segundo 220 kV substation, electricity will be transmitted to users by the existing transmission and distribution network.

The existing 220 kV SCE switchyard on site can be available to draw power for the new desalination plant. Alternately, the site also has a 66 kV feed. Nexant has contacted SCE and requested details on 220 kV and 66 kV switchyard configurations after NRG tie in with new combined cycle plant is completed. The 66 kV switch yard provide double loop feed and is able to support the project need for up to 50+ MW of power.

3.4.2. AES Redondo Beach Generating Station

AES Redondo Beach, LLC, owns and operates 4 steam generating units (Units 5–8) at RBGS in the city of Redondo Beach, Los Angeles County.

Four other steam units (Units 1-4) have been retired but remain on the facility property. Units 5-8 at RBGS are used infrequently; with the 2006 combined capacity utilization rate was approximately 5 percent. The 2011 AES reported capacity factors for Units 5, 6, 7 and 8 were 2.5%, 1.2%, 8.9%, and 0.2% respectively[7].

Table 3-6: RBGS General Information

Unit	In Service Year	Rated Capacity (MW)	Cooling Water Flow[8] (gpm)
Unit 5	1954	175	72,000
Unit 6	1957	175	72,000
Unit 7	1967	480	234,000
Unit 8	1967	480	234,000
RBGS total		1,310	612,000

Figure 2-5 show site layout for the RBGS station with 220 kV and 66 kV switch yard.

[7] CA CEC form 1304 Annual Energy statistics for Plant ID G04090.
[8] Tetra Tech Report – California Coastal Power Plants, Alternative Cooling System Analysis AES RBGS

Figure 3-5: AES RBGS Site Layout

California Coastal Commission has issued directive to phase out once through cooling of coastal power plants. At present, AES's future plan for the RBGS is unknown. However, AES has indicated through public workshops with the City of Redondo Beach that they are pursuing submitting an Application for Certification (AFC) for repowering of RBGS.

The onsite 66 kV line at RGBS station has Triple feed and will be able to support desalination plant load. The line has in excess of 50+ MW of electricity carrying capacity.

4. SCE Supply Options

4.1. Basic Services

The SCE service for the desalination plant will fall under large users with electrical load >500 kW. SCE can supply power under standard distribution voltages. The distribution voltages offered by SCE are: 120, 120/240, 240, 240/480, 277/480, 2,400, 4,160 volts; or, depending on location, 4,800, 12,000, 14,400/24,900, 16,500 or 33,000 volts.

Two sites under consideration have following features:

1. The NRG El Segundo Site- this site is served with a 220 kV line used for power evacuation. The site is also served by two 66 kV lines on opposite sides of the property. However, SCE will have to verify how the 66 kV lines are fed. To best of SCE's records, the 66 kV feed lines were used to start-up old units and are not actively being used.

2. AES Redondo Beach Site – this site is served by a 220 kV transmission line that is also used to evacuate station power when the AES Redondo Beach plant is running. The site is also served by three 66 kV lines with onsite substation. These were used for the old units at the site and now are used for power feed to the station. With the current 66 kV feed lines, there will be sufficient redundancy for the desalination plant. SCE has capability to feed this from different sources.

3. SCE mentioned in a meeting with WB and consultants that engineering study will be required to determine how the site will be fed. The cost of such study will be $75K -$100K.

For both sites, 66 kV feed to the customer under Standard Service contract will likely be a no cost to customer. However a basic service determination would be required by SCE to confirm 66 kV is basic service and not something smaller.

Under the basic services, SCE customers' electricity rates are established by the California Public Utilities Commission (CPUC), the government body that regulates all investor-owned utilities in the state. The CPUC assesses rates every three years through General Rate Case proceedings.

SCE Rates can be evaluated under three different scenarios and some variations of it. The three options are:

Option 1: SCE provides 66 kV service with meter installed at the 66 kV line with a breaker provided by SCE. Customer installs necessary transformer and downstream breaker and is responsible for capital and maintenance cost of the transformer. From Energy delivery this is the least cost option for SCE charges (it excludes capital and O&M charges for the 66 kV transformer).

Option 2: SCE provides 66 kV service as per Option 1, but also installs 66 kV transformer and contracts for maintenance. SCE will recover the capital and O&M costs through a fixed monthly charge to West Basin. SCE selling point for Option 2 was it can provide better reliability and prompt service for maintenance than any third party providers. O&M costs are approximately $100k per year.

Option 3: SCE provides 4 kV/12 kV service to customer under Standard Service Contract. There is no charge for 66 kV switchyard or transformer. However, energy cost under current rate schedule will be highest.

An outline of these options is presented in **Appendix 2:B**.

4.2. SCE Rate Structure

SCE tariffs and programs for large power customers, also called General Service (GS) customers is determined by the demand thresholds. GS customers are also eligible for various demand response programs. Detailed information on demand response programs is available online at www.sce.com/drp.

Table 3-1 is summary of SCE rate basis for large users with electrical load >500 kW.

Table 4-1: Large User Rate Basis

Rate Schedule	Eligibility	Rate Type	Customer Charge	Demand Charge	Energy Charge	Other Options
RTP-2	Bundled service customers >500 kW	Optional for TOU-8 accounts Seasonal Temperature driven hourly pricing	Charge per meter, per month	Facilities Related	Temperature Driven	Power factor adjustment per kVAR Voltage discount as applicable Interval meter required
TOU-8 (primary voltage 2 kV-50 kV)	>500 kW	Mandatory for accounts >500kW Seasonal Time of Use	Charge per meter, per month	Facilities Related On-peak & mid peak demand charges	On peak, mid peak and off peak energy charges that are no lower in winter and higher in summer	Power factor adjustment per kVAR Voltage discount as applicable Interval meter required

Figure 3-1 and **Figure 3-2** outline the SCE transmission lines serving the proposed two sites and a metering scheme for the TOU-8 rate base. Additional metering options are provided in **Appendix 2:B**.

Figure 4-1: Power Supply Arrangement from SCE – 220 kV Supply

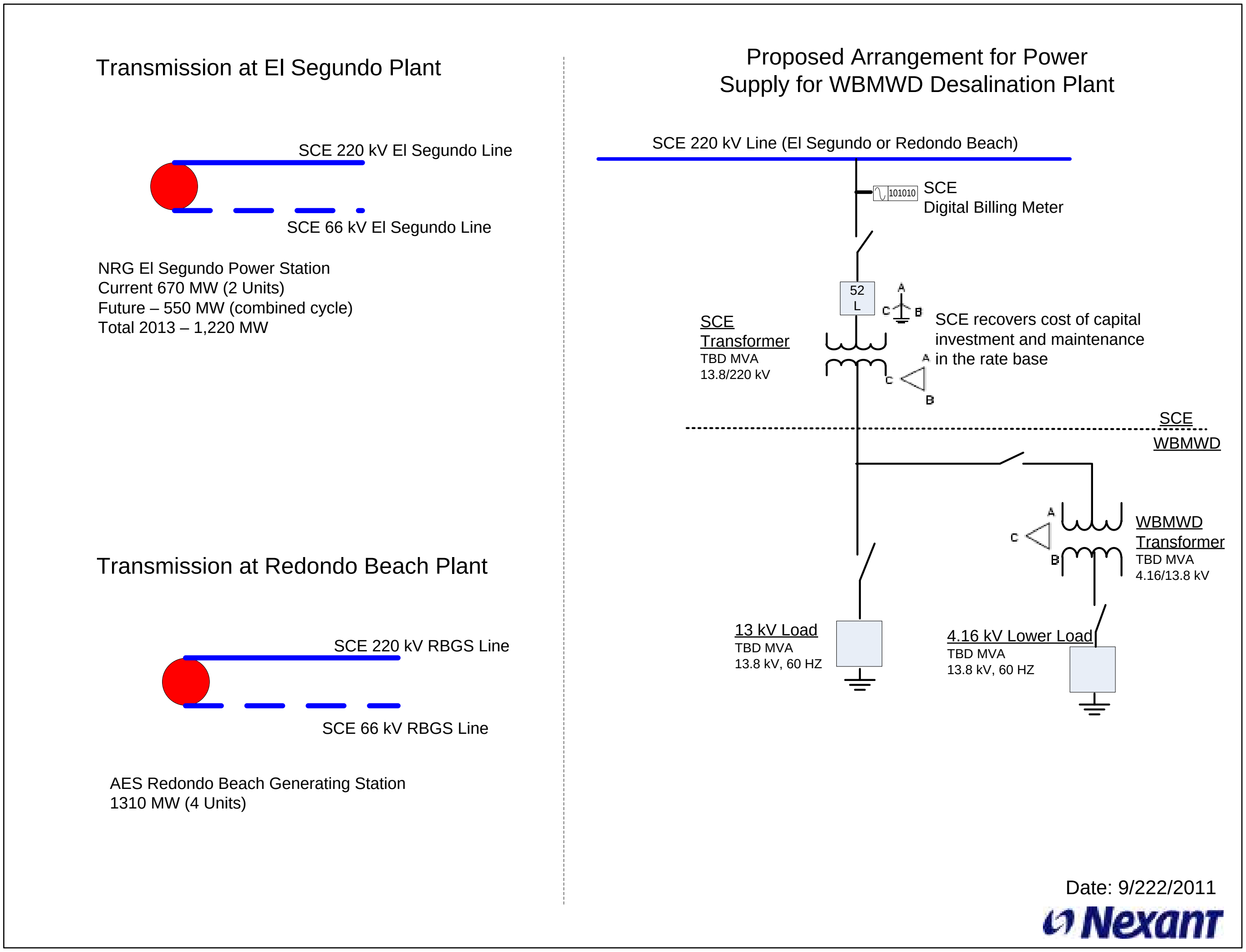
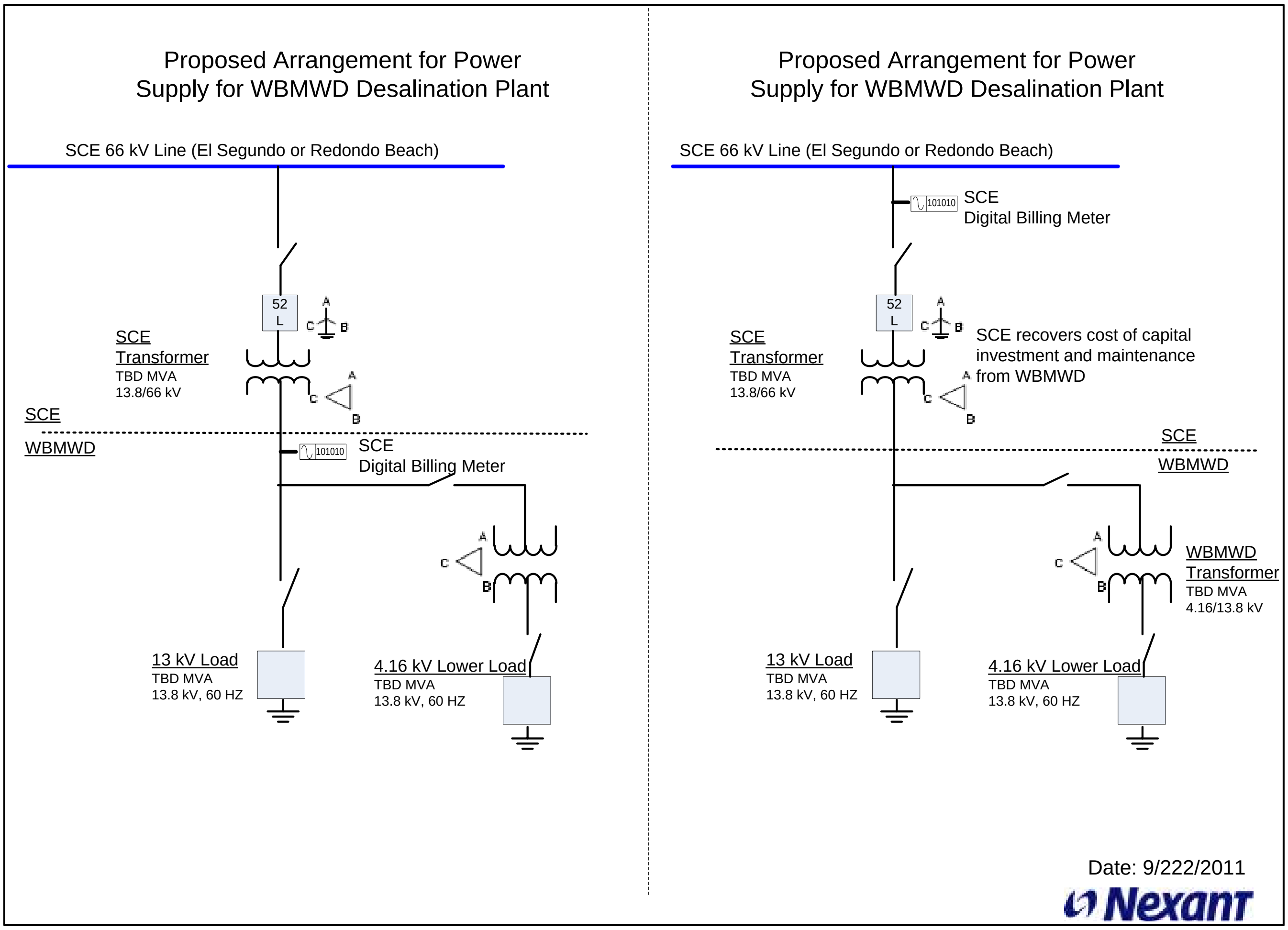


Figure 4-2: Power Supply Options from SCE – 66 kV Supply



4.2.1. Energy Charges

Energy charges are determined based on rate schedule selected by the customer. As shown in **Table 3-1**, under real time pricing, the energy charges are temperature driven and determined by average hourly temperature at the LA City Hall. For TOU-8, energy charges fall under three different periods shown in **Table 3-2**. The highest charges are for summer mid-day, and are lowest during off-peak hours and during weekend throughout the year.

4.2.2. Transmission Charges

Facilities-Related Demand charges reflect the cost of transmission and distribution facilities built to meet customers' peak power demands and are applied all year round. These charges recover SCE's costs for transporting electricity over long distances, such as from generating stations to substations at the plant location. An example of transmission charges is provided in **Table 3-3**.

4.2.3. Maintenance Charges

Monthly charges for repair and replacement of the meters or Metering Facilities that are not provided by SCE but requested by the customer vary based upon installation costs and type of equipment to be maintained. Metering Services include services provided by SCE that are in addition to and/or associated with the services described in the rate schedule and/or in the Interval Data Recorder (IDR) that are requested by the customer. Such services shall be charged on a time and materials basis (T&M). The charges are calculated based on SCE's total costs to provide Other Metering Services.

1. Metering Facilities installed by SCE on a time and materials basis in accordance with SCE rate Schedule; Other Metering Services include services provided by SCE that are in addition to and/or associated with the services described in this Schedule and/or in the Interval Data Recorder (IDR) Metering and Metering Facilities Agreement (Form 14-655). Such services shall be charged on a time and materials basis (T&M).

2. IDR meters over one (1) year old which were not installed by SCE; and

3. IDR meters over one (1) year old which were installed by SCE, but were not continuously maintained by SCE during the life of the meter.

These charges cover standard installation on a customer-owned meter panel which is in good condition. Unusual installations will be charged on a time and materials basis, in accordance with SCE maintenance Schedule.

Maintenance of customer or SCE installed switchyard and transformer for the benefit of customer will be based on fixed contract terms and services required by

4.2.4. Standard vs. Added Facilities

Added Facilities are:

a) Facilities requested by customer which are in addition to or in substitution for standard facilities (such as SCE's standard line and service extension facilities), which would normally be provided by SCE for delivery of service at one point, through one meter, at one voltage class under its tariff schedules, or

b) A pro rata portion of the facilities requested by an applicant, allocated for the sole use of such applicant, which would not normally be allocated for such sole use.

Added Facilities may include, but are not limited to, all types of equipment normally installed by SCE in the development of its electrical transmission and distribution systems and facilities or equipment related to SCE's provision of service to a customer or a customer's receipt or utilization of SCE's electrical energy. Added Facilities also include the differential costs for equipment for electrical transmission and distribution systems designed by SCE which, in SCE's sole opinion, is in excess of equipment required for SCE's standard serving system. Added Facilities may include poles, lines, structures, fixtures, transformers, service connections, load control devices and meters.

However, the installation of meters capable of recording and providing interval data that are in addition to or in substitution for standard meters shall be provided under the provisions of Interval Metering Facilities as Added Facilities.

Added facilities will be installed under the terms and conditions of a contract in the form on file with the California Public Utilities Commission. Such contract will include, but is not limited to, the following terms and conditions:

a. Where new facilities are to be installed for applicant's use as added facilities, the applicant shall advance to SCE the additional installed cost of the added facilities over the cost of standard facilities. At SCE's option, SCE may finance the new facilities.

b. The following monthly ownership charges are applicable to Added Facilities
    1. Applicants being served by SCE-financed added facilities shall pay a monthly ownership charge of 1.33% of the cost associated with the added facilities.
    2. Applicants being served by the Customer-financed added facilities shall pay a monthly ownership charge of 0.47% of the cost associated with the added facilities.

4.3. Time of Use (TOU) Rates

TOU-8 rate schedule[9] is applicable to general service including lighting and power, except agricultural water pumping accounts. This Schedule is applicable to and mandatory for all customers whose monthly maximum demand, in the opinion of SCE, is expected to exceed 500 kW or has exceeded 500 kW in any three months during the preceding 12 months.

Service under this Schedule is subject to meter availability.

TOU-8 Schedule contains four rate structures; Critical Peak Pricing (CPP), Option A, Option B, and Option R. Details of these plans are available upon formal request for utility connection. West Basin will have to make a formal request to SCE for details on these rates.

[9] SCE TOU -8 rates, Advise 2550-E, effective March 3, 2011. www.sce.com

Rate Schedule TOU-8 separates basic charges into:

- A monthly Customer Charge that covers a portion of basic services, such as meter reading and customer billing;
- Energy Charges per kilowatt-hour (kWh) consumed that vary by season and time of day; and
- Demand Charges consisting of Time-Related Demand and Facilities-Related Demand charges.
    - The Time-Related Demand Charge is applied only during SCE's summer season. This charge helps recover part of SCE's higher costs of providing transmission and distribution services during the high demand summer season. It is a per-kW charge applied to the greatest amount of registered demand in each summer season billing period (note: Time interval to measure for Time-Related Demand Charges is not spelled out in the published rate structure, and will have to be clarified with SCE).

The Facilities-Related Demand Charge is also billed on a per-kW basis, yet it is in effect in each billing period throughout the year. It is applied to the greatest amount of registered demand in each billing period. This charge is necessary to recover costs for the installed transmission and distribution facilities required to serve customer's highest demand during the year.

Table 3-2 is summary of TOU period currently defined by SCE and estimated hours in the year for each period. The hours are calculated based on SCE definition for holidays and based on 52 weeks. Actual hours in a period may vary slightly from year to year, depending on if the holidays fall on weekend or weekdays.

Table 4-2: Time of Use Periods for TOU-8

Time of Use Periods		Mon	Tue	Wed	Thur	Fri	Sat	Sun
Summer Season	8 AM - Noon							
June 1 - September 30	Noon- 6 PM							
	6 PM - 11 PM							
	11PM - 8 AM							
Winter Season	8 AM - 9 PM							
October 1 - May 31	9 PM - 8 AM							
				Summer	Winter	Total		
			Days	122	243	365		
On Peak - Highest Energy Charge			Hrs	516	0	516		
Mid Peak - Medium Energy Charge			Hrs	774	2171	2945		
Off Peak - Lower Energy Charge			Hrs	1638	3661	5299		

The current SCE electricity charges for TOU-8 for large users are outlined in **Table 3-3**. This includes energy charges, kW demand charges, power factor adjustment, and reactive power charges. These are indicative rates, and for TOU billing scheme. SCE will provide detailed breakdown of billing charges based on overall service requested by the customer.

Table 4-3: Electricity Charges for TOU for >500 kW at >50 kV

Time Period		On Peak	Mid Peak	Off Peak
Delivery Service Charges	$/kWh	0.01616	0.01616	0.01616
Energy Charges Summer	$/kWh	0.1261	0.09968	0.07139
Energy Charges – Winter	$/kWh	0	0.09318	0.07101
		For All Periods		
Customer Charge	$/meter/month	2376.08		
Demand Charges	$/kW /month	4.63		
PF Adjustment	$/kVAR	0.32		
Demand Charge Discount	$/kW /month	-1.99		

4.4. Real Time Pricing (RTP)

SCE rate schedule RTP-2[10] is applicable to Bundled Service Customers eligible for service under Schedule TOU-8, General Service - Large. This Schedule is limited to customers who agree to participate in the Real Time Pricing ("RTP") program and is subject to meter availability. Under this rate schedule the following is applicable:

- Maximum Demand: The Maximum Demand for the billing month shall be the measured maximum average kilowatt input indicated or recorded by instruments, during any 15-minute metered interval in that billing month. Where the demand is intermittent or subject to violent fluctuations, a 5-minute interval may be used.
- Billing Demand: The Billing Demand shall be the kilowatts of Maximum Demand determined to the nearest kW. The kW of Billing Demand used to determine the Facilities Related Demand Charge shall be based on the kilowatts of Maximum Demand recorded during (or established for) the monthly billing period. However, when SCE determines the customer's meter will record little or no energy use for extended periods of time or when the customer's meter has not recorded a Maximum Demand in the preceding eleven months, the Facilities Related Demand Charge may be established as 50 percent of the customer's connected load.
- Real Time Pricing: As used in this schedule, Real Time Pricing is the practice of continuously varying prices to customers to reflect simulated hourly variations in the marginal costs of generating electricity. Detailed hourly rates for each month can be downloaded from SCE web site.

[10] SCE RTP-2 rates, Advise 2577-E-A, effective June 1, 2011. www.sce.com

- Voltage Discounts: Bundled Service Customers will have the Distribution rate component of the applicable Delivery Service charges reduced by the corresponding Voltage Discount amount for service metered and delivered at the applicable voltage level as shown in the Rates section above. In addition, Customers receiving service at 220 kV will have the Utility Retained Generation (URG) rate component of the applicable Generation Charges for service above 50 kV reduced by the corresponding Voltage Discount amount for service metered and delivered at 220 kV as shown in the Rates section.
- Power Factor Adjustment: The customer's bill will be increased each month for power factor by the amount shown in the Rates section above for service metered and delivered at the applicable voltage level, based on the per kilovar of maximum reactive demand imposed on SCE.
  - The maximum reactive demand shall be the highest measured maximum average kilovar demand indicated or recorded by metering during any 15-minute metered interval in the month.
  - The kilovars shall be determined to the nearest unit. A device will be installed on each kilovar meter to prevent reverse operation of the meter.

The daily maximum temperature, as recorded by the National Weather Service, at its Downtown Los Angeles site, will be used to determine the hourly rates for the following day according to the RTP-2 rate schedule. It is the responsibility of the customers to acquire the daily maximum temperature at the Los Angeles Downtown site. SCE is not required to provide the daily maximum temperature. In the event that data is unavailable from Downtown LA as the primary source, data collected by the National Weather Service from Long Beach Airport shall be used. Where data is not available from either site, SCE shall enact its procedure for emergency data collection in order to provide substitute temperature data.

4.5. Added Facilities Costs

Added Facilities is defined as:

a. Facilities requested by an applicant which are in addition to or in substitution for standard facilities (such as SCE's standard line and service extension facilities), which would normally be provided by SCE for delivery of service at one point, through one meter, at one voltage class under its tariff schedules, or
b. A pro rata portion of the facilities requested by an applicant, allocated for the sole use of such applicant, which would not normally be allocated for such sole use.

Added Facilities may include, but are not limited to, all types of equipment normally installed by SCE in the development of its electrical transmission and distribution systems and facilities or equipment related to SCE's provision of service to a customer or a customer's receipt or utilization of SCE's electrical energy. Added Facilities also include the differential costs for equipment for electrical transmission and distribution systems designed by SCE which, in SCE's sole opinion, is in excess of equipment required for SCE's standard serving system. Added Facilities may include poles, lines, structures, fixtures, transformers, service connections, load control devices and meters.

Added facilities will be installed under the terms and conditions of a contract in the form on file with the California Public Utilities Commission.

4.6. Interruptible Power Option

The Time-of-Use Base Interruptible Program (Schedule TOU-BIP) is open customers who have monthly demands (or aggregated demands) that reach or exceed 200 kW. Customers or aggregated groups who select this program are required to choose a Firm Service Level (FSL) that reflects the amount of electricity the customer determines is necessary to meet their operational requirements during a TOU-BIP event. They must also choose a participation option, which is the amount of time (15 or 30 minutes) the customer requires in order to respond to a TOU-BIP event. Customers must make a commitment to reduce at least 15% of their maximum demand (but no less than 100 kW) during TOU events.

In exchange for participating in TOU-BIP, customers or aggregators receive monthly credits based on the difference between their average peak period demand for each month and their selected FSL. TOU-BIP credits for each billing period will be applied to the current month’s bill. Excess energy charges (penalties) apply for failure to reduce power to the customer-selected FSL within the selected participation option (15 or 30 minutes). Some restrictions apply. For example, Essential Use* and Exempt** customers cannot set their FSL to less than 50% of their average maximum demand.

The credits under TOU-BIP will depend on amount of load reduction agreed by customer. In general terms for the desalination plant, if WB agrees to reduce the load by 1 MW (to a pre-committed firm service level – FSL) during peak demand period month, SCE credits will be in the range of $18,000 to $19,000/MW for the month. For mid peak period, the credits will be ~$5,000/MW and only about $1,000/MW during off peak winter months.

Eligibility - Schedule TOU-BIP is optional to TOU-GS-3, TOU-8 and Real-Time Pricing (RTP-2) customers. Participation in Other Demand Response Programs with limitations, customers participating in TOU-BIP may also participate in other demand response programs for additional incentives.

Customer Obligations - Directly-enrolled customers and aggregators taking service under TOU-BIP must agree to the following conditions:

- Firm Service Level (FSL): The customer must establish a FSL, which is the amount of electricity a TOU-BIP customer determines is necessary to meet their operational requirements during a TOU-BIP event. This is also the amount of load that would not be subject to interruption during a TOU-BIP event. TOU-BIP customers are required to reduce their electrical load to their designated FSL within the time frame of their selected participation option.
- Participation Option (15 or 30 Minutes): Customers must select an amount of time they need in order to respond to the TOU-BIP event — 15 minutes (Option A) or 30 minutes (Option B) after receiving a notice of interruption.
- Remote Terminal Units for Notices of Interruption: TOU-BIP customers must have a working remote terminal unit (RTU) to receive a notice of interruption. The RTU will be provided by SCE.
- Telephone lines: TOU-BIP customers must have one dedicated, unlisted telephone line and telephone for the sole purpose of receiving official TOU-BIP event notifications, and may be required to have an additional dedicated phone line for the RTU.
- Interval meter: Customers must have an interval meter capable of recording usage in 15-minute intervals. If the customer does not already have an interval meter, SCE will provide and install one at no charge (certain restrictions apply).

Program Operation

Interruption Frequency and Duration - A TOU-BIP event may occur after SCE receives a request from CAISO to reduce a specific amount of electrical load. SCE will notify its TOU-BIP customers to reduce electrical usage to their FSL within their selected participation option time frame - 15 minutes (Option A) or 30 minutes (Option B) - of receiving the notification, to avoid penalties. TOU-BIP interruption events are limited to:

- No more than one event per day (up to 6 hours), or
- No more than 10 events per calendar month, or 120 hours per calendar year
- CAISO can call for a TOU-BIP event at any time, 24 hours a day, 7 days a week, 365 days a year

Initiation of TOU-BIP events - Events initiated by CAISO: A TOUBIP event may be triggered by CAISO at a Stage 2 Emergency.

Events initiated by SCE: SCE may trigger a TOU-BIP event, upon the determination of the need to implement load reduction in our service territory; or for test purposes, program evaluation or system contingencies.

Penalties, or “excess energy charges”, are applicable when a customer fails to reduce their electrical usage to their FSL during these events.

5. Power Supply Development

5.1. Reliability & Integration Standards

Federal Energy Regulatory Commission (FERC) has established North American Electric Reliability Corporation (NERC) and developed rules for reliability of electric supply throughout North America. SCE as provider of the electricity in the region is required to follow these rules and meet the reliability standards set by NERC.

Under FERC rules, electricity industry is required to operate under mandatory, enforceable reliability standards. The NERC is responsible for developing and enforcing these standards as one means of improving the reliability of North America's bulk power system. The bulk power system consists of the power plants, transmission lines and substations, and related equipment and controls, that generate and move electricity in bulk to points from which local electric companies distribute the electricity to customers.

Reliability Standards address aspects of the operation and planning of the bulk power system such as: real-time transmission operations, balancing load and generation, emergency operations, system restoration and black start, voltage control, cyber security, vegetation management, facility ratings, disturbance reporting, connecting facilities to the grid, certifying system operators, and personnel training. Standards detail how the system should perform, but not how the system should be designed. Individual owners, operators and users of the bulk power system determine if the system should be expanded or changed, and how, in order to achieve the standards.

Stated in simpler terms, these are federal enforceable standards that require that utilities and transmission operators provide dependable and clean power (set frequency and voltage to protect customer installation) 24/7 with very high reliability. Utilities are required to compile statistics on customer outages, and reasons for such outages, remedial action to prevent future occurrence on regular basis and file such reports with FERC. FERC has enforceable power to require utilities and transmission operators to upgrade their system and procedures to maintain these reliability standards.

5.2. Transmission Requirements

Both sites under consideration – NRG's ESGS and AES's RBGS have 66 kV transmission line services. The 66 kV line at ESGS was installed for starting the old ESGS plant. The substation is outside the fence as shown in **Figure 3-2**. However, the substation is active and available to tap into and can support the required load up to 50 MW for the desalination plant.

The 66 kV substation at RGBS is active and was used to evacuate power from old units 1-4, which are decommissioned. The substation has dual feeds to meet reliability requirements and it can support the required load for the desalination plant of 20 – 60 MGD capacity.

For either site, if West Basin decides to utilize SCE transmission and substation facilities, SCE will have to conduct a power flow analysis based on desalination plant size and power requirement to determine adequacy of the current installed system and if any upgrades are required. Per SCE, such study can cost in the range of $100K, but SCE can absorb such costs for the new customers.

5.3. Design Requirements

General single line scheme for power supply by SCE is provided in **Appendix 2:B**. For self-generation a single line scheme is presented in **Appendix 2:C**.

The detailed transformer specification for power supply options from SCE 66 kV line will be developed after detailed desalination power requirements are determined and SCE has conducted power flow analysis.

6. Power Supply Cost Analysis

6.1. On Site Generation Cost Estimates

Table 5-1 is budgetary cost estimate based on current NG fuel price of \$4.50/MMBtu and recently published costs for the combined cycle plants in Gas Turbine World[11]. The following assumptions were used in developing **Table 5-1**.

1. CC Net output was developed from GTW Handbook for typical configuration with standard manufacturer's offering without duct firing
2. Heat Rate was based on published GT heat rate and for ST efficiency
3. Annual power generation was estimated based on 92% capacity factor
4. Fuel cost was estimated at \$4.5/MMBtu and heat rate for the individual model
5. Capital cost were based on GT World estimate and recent available cost data
6. Cost data are for turnkey EPC work for a developed site. Does not include land lease or land acquisition cost, Owner's cost (permitting, and financing cost, etc.) and switchyard development or gas supply infrastructure cost outside the fence.
7. Annual Capex was estimated at 25 year bond financing for 100% debt at 5 ¼ % interest rate, no taxes or other fees
8. Fixed and variable O&M costs were estimated based on Nexant's in-house experience and data base for CC units from various sources including DOE, EPRI, and standard offering by IPP in their PPAs.

[11] Gas Turbine World 2010 Handbook, Vol. 28. Gas Turbine World, P.O. Box 447, Southport, CT 06890, USA,, Gas Turbine World, P.O. Box 447, Southport, CT 06890, USA

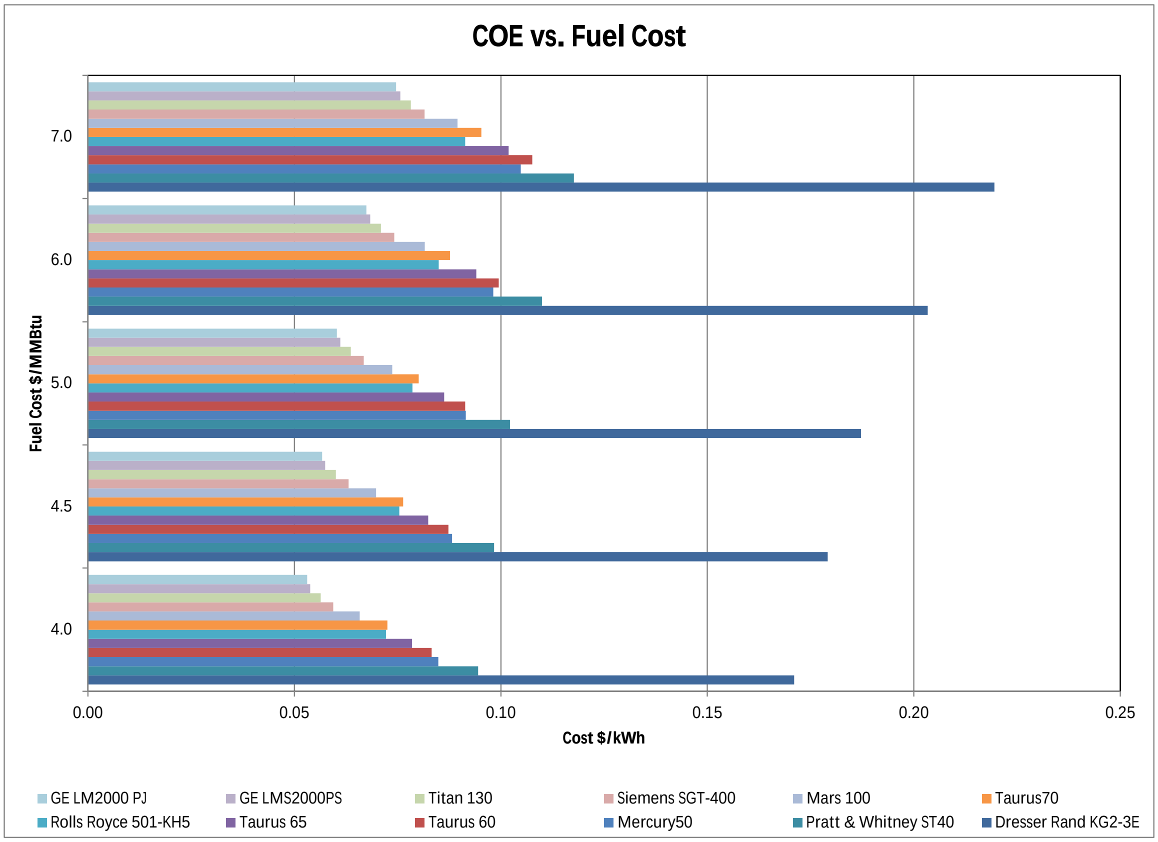
Table 6-1: Budgetary Cost Estimate for Combined Cycle Generation

Combined Cycle	Continued Cycle Net Output	Heat Rate	Annual Power Generation	Annual	CAPEX	Estimated CapEx	Annual CapEx	CapEx Cost	Fuel Cost	Estimated O&M Cost	Total Estimated Cost
Model 1	MW	Btu/kWh	Annual GWh	Fuel Cost $	$/kW	Million $	$	$/kWh	$/kWh	$/kWh	$/kwH
Dresser Rand KG2-3E	2,526	16,164	20	2,303,061	3,136	8	576,121	0.028	0.113	0.08	0.22
Pratt & Whitney ST40	5,383	7,736	43	2,349,214	2,317	12	907,219	0.021	0.054	0.04	0.12
Mercury 50	6,131	6,650	49	2,300,004	2,199	13	980,850	0.020	0.047	0.04	0.10
Taurus 60	7,557	8,126	61	3,464,188	2,023	15	1,111,982	0.018	0.057	0.03	0.11
Taurus 65	8,397	7,784	68	3,687,386	1,939	16	1,184,547	0.018	0.054	0.03	0.10
Rolls Royce 501-KH5	8,593	6,384	69	3,094,754	1,922	17	1,201,054	0.017	0.045	0.03	0.09
Taurus 70	10,023	7,578	81	4,284,787	1,807	18	1,317,281	0.016	0.053	0.03	0.10
Mars 100	13,901	7,889	112	6,187,049	1,585	22	1,602,944	0.014	0.055	0.02	0.09
Siemens SGT-400	17,193	7,366	139	7,144,208	1,456	25	1,820,965	0.013	0.052	0.02	0.08
Titan 130	19,992	7,274	161	8,204,064	1,371	27	1,993,437	0.012	0.051	0.01	0.08
GE LMS 2000PS	23,533	7,283	190	9,669,231	1,284	30	2,198,356	0.012	0.051	0.01	0.08
GE LM 2000PJ	23,911	7,168	193	9,669,092	1,276	31	2,219,461	0.012	0.050	0.01	0.07

It should also be noted that onsite generation will require SCE back-up power during forced and planned outages. The standby charges will be based on Schedule S as outlined under Section 3.7 Standby Charges. These are over and above COE estimated in **Table 5-1** above. An example of SCE standby charges is provided in Section 5.4.

Sensitivity Analysis: As estimated in **Table 5-1**, the major element in COE is fuel cost. Current NG fuel cost for generating electricity in California (2012 spot market price per CEC and CPUC) is between $4 - $4.50 /MMBtu gas delivered at site. However, in the past the price has fluctuated between $3.85 - $9 /MMBtu. US DOE projection for long term NG price is to remain soft and in the range of $3.50 - $4.50 /MMBtu. The Chart 5-1 show impact of fuel price on COE.

Figure 6-1: COE vs. Natural Gas Price



Stand by Charges for Onsite Generation

Onsite generation will require backup power during scheduled and unscheduled plant outages. Most combined cycle units have high availability, and range in 90-95%. The above analysis has assumed 92% availability factor. SCE will provide the required backup power that will be uninterruptible power with seamless auto transfer. SCE will assess standby charges. An analysis for standby charges is provided in Section 5-4. Redundant units to avoid stand by charges is not considered, as it will be cost prohibitive. The redundant unit will have a design capacity factor of 15-20%. At this capacity factor capital recovery cost of second unit will be higher than stand by charges from SCE. However, a small emergency generator or UPS system should be part of any power system design to safely shutdown both desalination plant and power plant in case of loss of power.

6.2. SCE Supply Cost Estimates

Table 5-2 is estimate of SCE cost of electricity based on TOU-8 rates services offered by SCE. These rates do not include any monthly charges for added facilities and applicable taxes. SCE calculated these costs based on peak demand of 15 MW and 33 MW and an estimate of annual energy use for 20 MGD and 40 MGD plants. Although, electrical load for these two cases is estimated at 14 MW and 30 MW respectively, SCE calculates peak demand charge on maximum load over any 15 minute interval for the month. If there is power surge due to major equipment starts, this will be counted toward fixed demand charge for the month. In order to be conservative in their estimate, SCE assumed 15 and 33 MW to calculate demand charges for the two cases.

Table 6-2: SCE Costs Under TOU-8 Rate

Plant Size (Peak Load) / Voltage	Total Cost (c/kWh)	Demand (c/kWh)	Energy (c/kWh)
15 MW at Less than 50kV	9.56	2.76	6.80
15 MW at Greater than 50kV	7.46	1.60	5.85
33 MW at Less than 50kV	9.56	2.76	6.80
33 MW at Greater than 50kV	7.45	1.60	5.84

Note:
2012 rates
>50kV is for 66 kV line

It should also be noted that SCE will require a study for any non-standard configuration which will be billed to WBMWD. Any other facility upgrades requested by WBWMD for SCE supply option will be billed separately.

6.3. Standby Costs for Self Generation

For self-generating power customers SCE rate schedule S or standby charges may apply. SCE's Rate Schedule S is mandatory for customers who self-generate all or a portion of their electrical power from their own generating facility, or from a third-party's generating facility.

Under Schedule S, SCE provides "standby" service, which is usually during the generator's scheduled or unscheduled outages (other than power outages or rotating outages). Schedule S ensures that customer's business will not be compromised when its generator is not operating.

One or more of the following basic charges may be applicable. Schedule S basic charges:

- Capacity Reservation Charge (CRC), based on the Standby Demand level (in kilowatts) set by the customer, and usually equal to the nameplate rating of the generator.

- Generation Demand Charges for backup service, consisting of Time-Related Demand (TRD) charges.

Note: All other charges will be billed at the customer's Otherwise-Applicable Tariff (OAT), including energy charges per kilowatt hour consumed, customer charges and demand charges for supplemental service (consisting of TRD charges and Facilities-Related Demand [FRD] charges). However, before rates are applied, any FRD charges will be offset by Standby Demand (in kilowatts) and any TRD charges will be offset by any Generation Demand TRD for backup service.

Schedule S requires:

- a contract,
- the presence of primary power equipment, and
- a generating facility interconnection agreement.

Under certain conditions, additional connection and metering equipment may be necessary.

Determining the level of standby demand - Standby Demand represents the entire reserve capacity needed to serve the customer's load that is usually provided when the generator is not operating. The level of Standby Demand is designated by the customer, but cannot exceed the nameplate capacity of the generator, the customer's connected load, or the prior 12-month peak demand (whichever is less). If, in any billing period, SCE determines the standby demand is too low or too high, SCE will increase or decrease the standby demand to reflect the actual required reserve capacity.

6.3.1. Basis for Standby Charges

Standby Charges were estimated based on the following assumptions:

Assumptions:

- 33 MW Standby (assuming that for desalination plant to run at full capacity at 33 MW power. This is for illustrative purpose. Other sizes can be used with similar results)
- No use of the standby (to keep it simple)

SCE's Demand charges were calculated based on the following formula provided by SCE.

Cost per year for Standby Service (At voltages less than 50 kV) –

33,000 KW X 5.13 X 12 (for T&D for the year) + 33,000 KW X 4 X 10.99 (Time Related Demand Charge for 4 Summer Peak months) + 33,000 X 4 X 2.78 (Time Related Demand

Charge for 4 Summer Mid Peak months) -

Cost per year for Standby Service (At voltages greater than 50 kV)

33,000 KW X 1.11 X 12 (for T&D for the year) + 33,000 KW X 4 X 9.83 (Time Related Demand Charge for 4 Summer Peak months) + 33,000 X 4 X 1.82 (Time Related Demand Charge for 4 Summer Mid Peak months)

Nexant has requested SCE for verification of these rates based on SCE published Standby rate schedule. We have not been able to obtain a written confirmation from SCE, but the following estimate represents a good maximum estimate. Actual cost for standby charges can be negotiated with SCE based on operational regime of the desalination plant.

6.3.2. Estimate for Standby Charges

The following **Table 5-3** is Nexant estimate for the annual standby charges. This does not include charges for energy that will depend on amount of electricity used and will be calculated on TOU-8 rate basis.

The Standby Charges were calculated for 33 MW service. Actual standby charges will depend on contract for the peak load for the desalination plant.

Table 6-3: SEC Standby Charges Estimate for a 33 MW Demand

Standby Charges for 33 MWs	**Reservation Charge**	**Time Related Demand Charges**		**Reservation Charge (T&D)**	**Time Demand Charge**	**Total Annual Charges**
	Reservation Charge Total T&D Factor	Time Related Summer On peak	Time Related Summer Mid Peak	Reservation Charge (T&D)	Time Demand Charge	Total Annual Charges
Less than 50kv	5.13	10.99	2.78	2,031,480.00	1,817,640.00	3,849,120.00
Greater than 50kv but less than 220kv	1.11	9.83	1.82	439,560.00	1,537,800.00	1,977,360.00

The accurate cost of standby charges per kWh of energy consumed will depend on many factors. This is an estimate. Based on current configuration of desalination plant, the standby charges are estimated at $0.015/kWh to $0.025/kWh. The above **Table 5-3** covers all periods during the year.

7. Preferred Alternatives

7.1. Ranking of Options

The power supply options analyzed in this report are ranked in **Table 6-1**.

Table 7-1: Ranking of Options

Power Supply Option	Advantages	Disadvantages	Conclusions	Cost Range
Onsite power generation with conventional means	Lower cost. Local control of power source and agreement terms.	Will require permitting and regulatory approval. Potential SCE standby charges. No renewable credits.	Obtaining emissions offsets and permitting is major hurdle. Economics marginal. WB has no experience in operating power plant but joint option could make feasible.	7-10 ¢/kWh (@$4.5/MMBtu gas price) + SCE stand by charges estimated at 1.5 – 2.5 ¢/kWh[1]
Onsite power generation by renewable resources	Attractive – green power.	Not very good wind or solar resources at site, not practical. Highest cost, with SCE supplying remaining power.	If implemented, on site renewable will generate <5% of power need of the desalination plant.	8 – 12 ¢/kWh for wind, 14-18 ¢/kWh for solar with SCE make up power at 7.5 – 9.6 ¢/kWh[2]
Power supply directly purchased from SCE	System reliability, defined contract terms and most accurate cost estimate. Will have 20-33% renewable component.	Current cost are well defined, but future escalation is subject to PUC process, and can have negative impact for large user to subsidize residential customers.	SCE >50 kV supply rates are competitive. SCE will work with WB within PUC guideline for best rates.	7.5 – 9.6 ¢/kWh[3]

Notes:

1. Nexant estimate calculated based on Gas Turbine World 2012 GTW Handbook, Volume 29 capital costs and estimated performance, Nexant in-house O&M cost estimate and DOE projected gas price for electricity generation
2. NREL Energy Analysis, July 2012 Update http://www.nrel.gov/analysis/tech_lcoe.html
3. SCE Cost Analysis – Based on work performed with SCE TOU -8 Rate Tables, and input from SCE Business Customer Division

7.2. Recommendations

Two options are recommend for WBMWD to evaluate going forward on site self-generation and direct purchase from SCE. Both options will require further detailed analysis of terms and conditions to determine the best alternative.

8. Next Steps and Schedule

8.1. Next Steps

Further negotiation will be required with SCE on standby charges, added facilities charges. If power is purchased from third party, wheeling costs will have to be negotiated with SCE.

For the self-generation option, WB may have to secure emission off-sets. Although, emission offsets have been available, there is no regulated market for the SCAQMD area. Individual entity deal with project developers and work out a price for selling or acquiring the off-sets. Since, these trades are few and commercial terms are not published, cost of acquiring the offsets, specifically for NOx, CO and particulates (PM_{10} and $PM_{2.5}$), are not available.

8.2. Schedule

Power supply option schedule should be integral part of overall PMP project. It is not a standalone power project. **Figure 7-1** presents a timeline for the SCE connection as well as for onsite self-generation.

Power purchase arrangement from SCE at high voltage should not take more than 3 quarters, including any system upgrades that may be required.

Self-generation option will require considerable upfront engineering and environmental work, and over all power project may take 10+ quarters.

Figure 8-1: Estimated Time Schedule for SCE and Self Generation Option