6. Retrofit and Repower Examples

1.0 General Summary

In recent years, alternative cooling methods—particularly wet and dry closed-cycle systems—have increasingly become the preferred approach for new steam electric facilities. The majority of all new conventional steam units constructed in the last two decades have used a closed-cycle system, with nearly all new combined-cycle units adopting this approach.

The economics and engineering considerations of a closed-cycle system are more favorable when part of a new facility's initial construction or a major overhaul. Altering the cooling system at an existing facility increases costs and can adversely impact the performance of the generating units. The decision to retrofit an existing facility from once-through cooling to closed-cycle is usually driven by extenuating circumstances that mandate a conversion, such as regulatory oversight or changes in water availability.

Repowering, on the other hand, is a more comprehensive upgrade or overhaul to the facility's generating system, including the boiler and turbine. When combined with a repowering project, closed-cycle systems become favorable, and may actually be preferable, to continued use of once-through cooling. In some respects, a repowered facility is similar to a new facility in that it has wider latitude in selecting an alternative cooling system.

2.0 Retrofit Examples

Retrofitting an existing once-through cooling system is a feasible alternative provided certain conditions can be met. Conversions, however, have been infrequent at large power plants. In its development of the Phase II rule, EPA identified three facilities that had undergone a closed-cycle retrofit—Jefferies Steam, Palisades Nuclear, and Canadys Station. This study identified three additional facilities—Plant Yates, Wateree, and McDonough—although information was available only for Plant Yates. Conversion of the Unit 7 cooling system at the Pittsburg Power Plant is California has also sometimes been considered a retrofit.

2.1 Jefferies Steam

The Jefferies Steam facility in South Carolina, owned and operated by Santee Cooper, consists of four steam-generating units. The plant was initially constructed in the 1950s with two oil-fired units to augment electric power production from the adjacent Jefferies Hydro facility. In 1970 two additional units, both coal-fired, with a rated capacity of 173 MW each (346 MW total), were added. The oil-fired units (1 and 2) remain available for service during critical periods but are used infrequently because of high fuel oil costs. All four units were initially designed with once-through cooling using water from Lake Moultrie, a constructed impoundment in the Santee Cooper River Basin.

In the 1980s the U.S. Army Corps of Engineers (USACE) determined that the impoundment project had created undesirable effects (principally sedimentation) downstream of the dam and proposed a rediversion project as mitigation. The rediversion canal that was constructed redirects water back to the Santee River, but has the effect of reducing the reliable water supply available to the Jefferies Steam facility. As part of a compensation agreement, the USACE-Charleston District funded the conversion of the Unit 3 and 4 once-through cooling system to a closed-cycle cooling (wet tower) system. The project was completed in 1985 (USEPA 2002).

The Jefferies mechanical draft wet cooling towers are made of concrete with PVC fill and designed with a 10° F approach temperature. New supply and return pipelines were constructed (1,700 feet total distance) using 108-inch reinforced concrete. The facility did not need to modify its existing intake structure and was able to use its existing once-through pumps to circulate water between the towers and condensers. Three new booster pumps were added to account for the increased pump head from the closed-cycle system. The facility also opted to install three new makeup water pumps, each rated at 1,950 gallons per minute (gpm), or 2.8 million gallons per day (mgd). No condenser modifications were required.

Santee Cooper conducted studies evaluating the efficiency penalty caused by the wet cooling towers. The maximum penalty, representing peak demand conditions, was 0.97 of the combined Unit 3 and 4 capacity, with an annual average penalty of 0.16 percent reported for 1988.

Units 3 and 4 retain their ability to use once-through cooling water, although wet cooling towers are the preferred operating mode.

Total cost information was not available for review.

2.2 PALISADES NUCLEAR

Palisades Nuclear plant in Michigan, currently owned and operated by Entergy Corp, is a 730 MW pressurized water reactor facility initially brought online in 1972. As originally designed, the facility used a once-through cooling system with a capacity rating of 486,000 gpm, or 700 mgd. Water was withdrawn from Lake Michigan through a 3,000-foot conduit extending offshore. The offshore intake continues to be used in the current closed-cycle system.

During the licensing proceedings in the early 1970s, citizen and environmental organizations petitioned to limit thermal discharges and radioactive releases from the radwaste system to Lake Michigan. The settlement agreement called for Palisades to convert its existing once-through system to closed-cycle as well as make other modifications to the facility.

Construction of two 18-cell mechanical draft towers began in 1971, with the towers becoming operational in 1974. Towers were designed to operate with the same condenser flow rate as the once-through system (400,000 gpm) and a 30° F cooling range. With the closed-cycle system, cooling water withdrawals initially decreased to 78,000 gpm, or approximately 86 percent. Additional modifications in 1998 further decreased the intake flow to 68,000 gpm, although the facility later obtained approval to increase the withdrawal rate to 100,000 gpm to moderate the impacts on plant efficiency. The net decrease from the original design is approximately 75 percent (USEPA 2004). Because the facility used the original intake structure, intake velocities decreased from 0.5 feet per second (fps) with the once-through system to 0.1 fps after conversion.

The closed-cycle system that came online in 1974 used the existing condenser as it was originally designed for the once-through system. A flaw in the original condenser system, however, led to increased vibrations and leaking during operations. Subsequent to the conversion, all condenser tubes were replaced, although no information is available describing the design changes, if any. New intake pumps were installed to withdraw makeup water from Lake Michigan and to circulate water between the towers and condensers. Dilution pumps were added to the recirculating system to increase the condenser flow to 460,000 gpm.

The facility reported a construction outage of 10 months during the connection and testing of the closed-cycle system because of necessary modifications to the system. Other activities such as condenser flaws and modifications to the radwaste system may have contributed to the outage time, but this cannot be conclusively determined.

The project’s reported installed cost was $18.8 million ($90 million in 2007 dollars) and included both towers (wood), fill material, drift eliminators, fans, four pumps, new pump houses, circulating water pipes, circulating water treatment system, and other necessary civil engineering and structural projects (e.g., drainage, structure demolition, and relocation) (USEPA 2002). Detailed descriptions of the cost elements were not available and cannot be accurately compared to costs developed in this study.

The facility estimated that the wet cooling towers resulted in 6–8 percent reduction in turbine efficiency compared with the once-through system, with a 20 MW increase in the parasitic load. No data are available to confirm these estimates.

2.3 CANADYS STATION

Canadys Station, located in South Carolina, consists of three coal-fired generating units owned and operated by South Carolina Electric with a rated generating capacity of 500 MW. Brought online in the 1960s, all three units were originally designed with once-through cooling systems drawing water from the Edisto River. Cooling system conversions were completed in two separate projects. The first, for Unit 3, was finished in 1972, with Units 1 and 2 retrofitted two decades later in 1992. Units 1 and 2 share a combined closed-cycle system.

Conversion to wet cooling towers at Canadys was largely driven by the lack of reliable cooling water volumes and possible thermal discharge impacts during low-water periods.

Unit 3, retrofitted in 1972, was initially fitted with a mechanical draft wood tower having a design approach temperature of 6° F. This tower was upgraded to a fiberglass model in 1999. The Unit 1 and 2 tower, constructed in 1992, is made of concrete with a design approach of 7° F. The relative distances between the cooling towers and the unit condensers required new circulating water pumps to handle the increased pump head. These distances (1,700 feet for Units 1 and 2; 650 feet for Unit 3) and the necessary piping likely contributed to a significant increase in capital cost for the projects, although no specific cost data were available for review.

Canadys installed new intake pumps to withdraw makeup water from the Edisto River through the original intake structure. No other significant modifications to the plant were reported. The facility did not modify its condensers for service in a closed-cycle system and has not reported any operational problems (USEPA 2002).

The cooling tower system for Units 1 and 2 was completed in approximately 8 months with a construction-related outage of roughly 30 days. The construction tie-in was scheduled to coincide with maintenance outages that were already planned.

2.4 PLANT YATES

Plant Yates, located in Georgia, is a coal-fired steam facility owned and operated by Georgia Power. The facility is rated at 1,250 MW, with seven generating units. Units 1–5 were brought online in the 1950s with a once-through cooling system that withdraws water from the Chattahoochee River. Units 6 and 7 were originally designed with closed-cycle systems.

The cooling tower constructed as a replacement for the Units 1–5 once-through system consists of 40 mechanical draft cells arranged in a back-to-back configuration. Flow reductions achieved with the tower are estimated to be 96 percent (600 mgd to 22). Costs for the retrofit project were reported at $87 million (Super 2002). Detailed information describing what was included in the reported cost was not available for review.

2.5 PITTSBURG POWER PLANT

The conversion of Pittsburg's Unit 7 cooling system is sometimes categorized as a retrofit in the same manner as the projects described above. Unit 7, brought online in 1972, was originally constructed with an enclosed cooling canal designed to recirculate cooling water from the condenser. Heat was rejected in the 6,000-foot-long canal through natural circulation and spray heads. The original canal did not provide sufficient cooling to allow Unit 7 to operate efficiently and was augmented with two mechanical draft wet cooling towers in 1976.

The new towers (crossflow design) were located on a backfilled portion of the center strip that divides the canal. Each tower consists of 13 cells.

Total project costs were reported as $48 million (2007 dollars). Incorporating cooling towers with the existing cooling canal enabled the facility to use much of the same infrastructure already in place (pipes, pumps).

No performance data were available for review.

3.0 REPOWER PROJECTS

Repower projects, as noted above, are more comprehensive in their modifications to the existing facility and often involve the complete demolition and replacement of an existing facility. In doing so, closed-cycle cooling options, particularly dry cooling, become more practical alternatives.

In California, five of the 21 coastal power plants have proposed repowering projects that eliminate the use of once-through cooling water, either in whole or in part—South Bay, Humboldt Bay, Contra Costa (Gateway), El Segundo, and Encina.

3.1 SOUTH BAY REPLACEMENT PROJECT

South Bay Power Plant (SBPP), in Chula Vista, is owned by the San Diego Unified Port District and operated by LSP South Bay, LLC (LSP). LSP has proposed to replace the existing facility with the South Bay Replacement Project (SBRP).[1] The existing SBPP consists of five generating units ranging from 35 to 45 years old and operated under a reliably must run (RMR) contract with the California Independent System Operator (ISO). The SBRB will provide sufficient replacement power for the existing facility, thereby allowing the removal of the RMR status and the demolition of the existing units. Four of the five generating units are natural gas–fired steam turbines (Units 1–4), while the remaining unit (GT-1) is a combustion turbine powered by fuel oil #5. Details on the existing operating units are presented in Table 6–1.

Table 6–1. Current South Bay Power Plant

Unit #	Type	Rated capacity (MW)	Existing flow (gpm)
Unit 1	Steam turbine	152	78,000
Unit 2	Steam turbine	156	78,000
Unit 3	Steam turbine	183	124,600
Unit 4	Steam turbine	232	136,800
GT-1	Gas turbine	15	--
Total		**738**	**417,400**

Cooling water for Units 1–4 is withdrawn from the southern end of San Diego Bay at a maximum rate of 602 mgd. Water withdrawals from and discharges to the bay are permitted under NPDES Permit CA0001368 as administered by the San Diego Regional Water Quality Control Board. The facility discharges elevated-temperature wastes to the bay along with low-volume wastes generated at the site.

[1] LSP South Bay, LLC withdrew its Application for Certification on October 22, 2007 following publication of the Administrative Draft.

3.1.1 PROJECT DESCRIPTION

The SBRP is designed to provide sufficient reliability to eliminate the RMR status of the SBPP. The new plant will consist of two natural gas–fired combustion turbines (General Electric 7FA), a heat recovery steam generator (HRSG), and a steam turbine, with a combined rating of 500 MW at 62° F. The new combined-cycle system is designed to operate at a heat rate of 6,993 BTU/kWh compared with the 10–12,000 BTU/kWh heat rates of the current steam units. This enables the SBRP to reduce air emissions on a per-kWh basis compared with the existing facility.

The HRSGs will be capable of duct firing, although duct firing increases the operating heat rate. With duct firing, the steam turbine's output would boost the plant's generation capacity to 620 MW, although duct firing is not planned to be used frequently.

A selective catalytic reduction (SCR) module will be attached to each combustion turbine's exhaust system to reduce air emissions. The SCR system will use ammonia vapor in the presence of a catalyst to reduce the NO_x in exhaust gases. The system will employ aqueous ammonia, which will be injected into the exhaust gas upstream of the catalyst. An oxidation catalyst will also be used to reduce the concentration of CO.

The existing facility exceeds the threshold defining a major facility under the prevention of significant deterioration (PSD) program. Since the SBRP would also exceed the threshold, the facility will remain a major facility after repowering. The change in air emissions with the repowering project, however, is less than the threshold at which it would be considered a major *modification*. Therefore, the SBRP would not have to undergo a review under the PSD regulatory program. The projected differences in air emissions between the existing facility and the SBRP are summarized in Table 6–2.

Table 6–2. SBRP and SBPP Air Emission Comparison

Pollutant	Existing SBPP baseline emissions (tons/year)	Maximum annual SBRP emissions (tons/year)	Net increase (decrease) in emissions (tons/year)
NO_2	106.5	104	(2.5)
SO_2	6.9	11	4.1
CO	763.5	544.6	(218.9)
PM_{10}	69.3	69.2	(0.1)

The SBRP will be located on 12.9 acres adjacent to the SBPP in what is referred to as the "former LNG site." Construction activities will include a new electrical system interconnection facility on 6.5 acres within the former LNG site. Natural gas will be provided to the facility in a new 16-inch pipeline connected to the current SBPP support infrastructure. The project area's zoning designation is General Industrial (I), which encourages industrial developments. The site is included within the Energy/Utility Zone as defined in the Chula Vista Bay Front Plan; an environmental impact report (EIR) will be prepared for the plan to meet California Environmental Quality Act (CEQA) requirements. Noise generated by SBRP's operations will be less than that generated from the current facility. Noise will be controlled by structural methods and equipment selection.

In terms of visual resources, the new facility will have a smaller footprint and a lower profile once demolition of SBPP has been completed. The boiler structures at the SBPP are 160 and 180 feet tall. SBRP's air cooled condenser (ACC) and exhaust stacks would be 94 and 125 feet tall, respectively. The preliminary assessment indicates that the new facility would be architecturally screened, resulting in less blockage of coastal views from the surrounding areas as well as a reduction in the contrast against the San Diego skyline to the north and mountains to the east. The visibility of the water vapor emissions would also be reduced.

3.1.2 WATER USE

Elimination of water withdrawals from San Diego Bay is one of the driving factors behind the development of the SBRP. Completion of the project and removal of the SBPP will eliminate the withdrawal of up to 602 mgd from the bay.

The steam turbine's cooling system will consist of the ACC system, which uses fin tube bundles grouped into modules and attached to a steel support structure. Steam from the steam turbine will enter the fin tubes as fans within each module force ambient air through the bundles, condensing the steam. Condensate will be collected and pumped back to the boiler feedwater system. In addition to the ACC, a closed-cycle cooling water system will be used to cool auxiliary equipment such as air compressors and bearing coolers. This system will consist of cooling water pumps, an expansion tank, and an air-cooled heat exchanger. Cooling of the heat exchanger will be accomplished similarly to the ACC, using bundles of fin tubes.

All the project's water requirements will be met using potable water sources. The SBRP's water demands result from a combination of boiler makeup supply for the steam cycle and onsite domestic uses. Daily use is projected at 80 gpm. All water will be supplied via the existing 10-inch main connected to the publicly owned Sweetwater Authority. SBRP wastewaters, consisting of sanitary and process wastes, will be discharged to the existing sanitary sewer connection at an approximate rate of 58 gpm.

3.2 HUMBOLDT BAY REPOWER PROJECT

Humboldt Bay Power Plant (HBPP), near Eureka, is operated by Pacific Gas and Electric (PG&E). The existing facility consists of four generating units. Units 1 and 2 are natural gas–fired steam turbine generators (Units 1 and 2) with a combined rating of 105 MW. The remaining two units are 15 MW, diesel-fired mobile emergency power plants (MEPPs). The MEPPS are used as backups when Unit 1 or 2 is offline or during peak winter load periods. HBPP was originally constructed with a nuclear-powered boiling water reactor steam unit (Unit 3), although it has not operated since 1976.

3.2.1 PROJECT DESCRIPTION

The Humboldt Bay Repowering Project (HBRP) replaces the existing facility (Units 1 and 2 plus MEPPs) with a load-following and cycling plant. The repowered facility will consist of 10 natural gas–fired Wartsila dual-fuel reciprocating engine generator sets with a total generating capacity of 163 MW.

Construction of the new units will require the demolition of some of the existing structures at the site. The existing units will remain in operation until the repowering process is complete. Ultimately, the HBRP will utilize some of the existing facilities, including the freshwater supply, natural gas pipeline systems, 60 kV (kilovolt) switchyard and transmission system, and the 115 kV transmission line currently originating from Unit 3. Three separate projects planned for the site include decommissioning of Unit 3; constructing the Independent Spent Fuel Storage Installation; and demolishing the HBPP (demolition of Units 1 and 2 and removal of the MEPPs).

The natural gas fuel requirement for each of the new units is approximately 139 MMBTU/hr. While the generators will mainly be powered by natural gas, they will also have the capability to run on diesel. When burning natural gas, a small amount of pressurized diesel will be injected into the combustion chamber to initiate the combustion cycle. This use of diesel as a pilot fuel would result in the consumption of a maximum of 75 gallons per hour assuming all 10 engines were operating at 100 percent load. Ultra-low sulfur diesel fuel (meeting California Air Resource Board standards) will be used only during emergencies or when gas supplies are curtailed. Curtailment occasionally occurs in winter months when natural gas is required for home heating needs, as required under the California Public Utilities Commission (CPUC) Gas Tariff Rule 14.

A SCR module will be attached to each engine's exhaust system to reduce air emissions. The SCR system will use ammonia vapor in the presence of a catalyst to reduce the NO_x in exhaust gases. The system will employ aqueous ammonia, which will be injected into the exhaust gas upstream of the catalyst. An oxidation catalyst will also be used to reduce the concentration of CO and VOCs.

Table 6–3 compares emissions from the HBRP with the existing facility. The emissions estimates in the table reflect the evaluation conducted for federal PSD and CEQA purposes. The numbers used for that analysis represent the maximum possible emissions, as opposed to emission rates that would be expected under normal operating conditions.

Table 6–3. HBPP and HBRP Air Emission Comparison

		Emissions (tons/year)				
		NO_x	**SO_2**	**CO**	**ROC**	**PM_{10}**
HBPP (Existing)	Unit 1	447.4	0.8	50.4	11.0	9.6
	Unit 2	404.6	0.8	51.5	11.2	9.8
	MEPP 2	17.3	1.1	2.1	0.5	2.6
	MEPP 3	23.4	1.2	2.4	0.6	3.0
	Total	**892.7**	**3.9**	**106.3**	**23.3**	**25**
HBRP (Planned)	Reciprocating engines	263.1	4.7	181.2	198.9	182.8
	Back start generator	0.4	<0.1	0.1	<0.1	<0.1
	Fire pump engine	0.2	<0.1	<0.1	<0.1	<0.1
	Total	**263.7**	**4.7**	**181.3**	**198.9**	**182.8**
	Net Increase (Reduction)	**(629.0)**	**0.8**	**75**	**175.6**	**157.8**

Repowering HBPP results in a large reduction of NO_x emissions, although emissions of SO_2, CO, ROC, and PM_{10} will increase. The Issues Identification Report for the HBRP identifies air quality as a potential issue, citing $PM_{2.5}$ reductions under the National Ambient Air Quality Standards (NAAQS). For reasons beyond the operator's control, natural gas shortages could cause the facility to burn diesel fuel for longer periods of time than considered in the modeling exercises submitted with the application for certification.

Noise is generated from various sources at the existing facility. Likewise, noise would be generated from a number of sources at the repowered facility, including combustion air inlets, transformers, pump motors, and fans. The existing facility is operating within Humboldt County zoning ordinances that address industrial noises. Based on information from vendors and suppliers, noises emanating from the repowered facility are expected to conform to local requirements (an industrial project should not raise the ambient noise by more than 5 decibels [dBA]).

3.2.2 WATER USE

The Wartsila engines used in the HBRP will be cooled with a closed-loop radiator system where cooling water circulates through tube bundles equipped with fins to radiate heat. Air circulation around the tubes will be assisted by fans. Propylene glycol will be added to the cooling water to improve heat transfer. The coolant system will be filled and maintained through separate maintenance tanks that allow recycling without the need for a discharge.

Once-through cooling water withdrawals from Humboldt Bay will be eliminated. The new generating engines, which reject heat through convection and radiation, reduce the facility's water demand from more than 40,000 gallons per minute (gpm) to approximately 1.67 gpm. Average annual discharge rates from HBRP would be less than 1 gpm (0.17 gpm closed loop engine cooling system; 0.32 gpm service use; 0.11 gpm domestic wastewater). Discharges of process and domestic wastewater will be to the local sanitary sewer system. Domestic water supply will be provided by the Humboldt Community Services District. Process water will be supplied via an existing well.

3.3 GATEWAY GENERATING STATION (CONTRA COSTA UNIT 8)

In 2001, the California Energy Commission (CEC) approved the application for certification (AFC) for the Contra Costa Power Plant (CCPP) Unit 8 project owned and operated by Mirant Delta, LLC. Construction began on the unit, although it was never completed. In late 2006, PG&E became the sole owner of CCPP Unit 8, renamed the project the Gateway Generating Station (GGS), and modified the system design. A comparison of the Unit 8 project as proposed by Mirant Delta and the current GGS project is summarized below.

The current facility consists of three retired units (Units 1, 2, and 3) and four operational units (Units 4, 5, 6, and 7). All the operational units are conventional natural gas–fired steam-generating units that use once-through cooling water from the San Joaquin River. Units 4 and 5 are used only as synchronous condensers and do not produce power for sale. Units 6 and 7 have a combined generating capacity of 680 MW. CCPP's existing National Pollutant Discharge Elimination System (NPDES) permit authorizes the withdrawal of up to 340 mgd of cooling water for Units 6 and 7. As approved, CCPP Unit 8 would have added an additional 530 MW of generating capacity to the existing CCPP complex.

CCPP Unit 8 would have used two natural gas–fired combustion turbine generators, HRSG, and steam turbine, with cooling provided by a 10-cell mechanical draft wet cooling tower. Cooling tower makeup water would have been withdrawn from the existing discharge canal used by Units 6 and 7; no new water would be withdrawn from the San Joaquin River unless Units 6 and 7 were not operational.

The GGS proposes to make use of the same power generation system—two natural gas–fired combustion turbine generators, HRSG, and steam turbine. The approved cooling system uses an ACC instead of the wet cooling tower, with makeup water supplied through the city of Antioch or another purveyor. The use of the ACC will eliminate the need for the 10-cell wet cooling tower and surface condenser. Compared with the Unit 8 project, GGS reduces the makeup water demand from approximately 8,300 gpm to 153.9 gpm. This is not a direct reduction of once-through cooling water withdrawals because the Unit 8 project would have recycled discharges from Units 6 and 7 when they were operational. The 80.9 million gallons per year water demand for the GGS will be provided by the city of Antioch or another supplier.

CCPP Unit 8 also included evaporative cooling for the combustion turbine air inlets. The GGS approach will replace evaporative cooling with an electric chiller system. The electric chiller will reduce combustion turbine inlet air temperatures to 50° F by drawing air across cooling coils containing water chilled with R134A refrigerant.

This system is separate from the ACC used for steam condensate cooling and will consist of a fin fan heat exchanger combined with either a small, wet surface air-cooled heat exchanger system or an evaporative precooler. The wet surface air cooler uses water sprayed over heat transfer bundles to increase cooling capacity through evaporation.

Air quality would be improved slightly, with lower $PM_{10}/PM_{2.5}$ emissions projected from the elimination of the cooling tower and addition of the wet surface air-cooled heat exchanger unit. The modeled emissions are presented in Table 6–4.

Table 6–4. GGS and CCPP Unit 8 Modeled Emissions

Operational source	NO_x	SO_x	CO	POC	$PM_{10}/PM_{2.5}$
GGS maximum annual emissions	174.3	48.5	259.1	46.6	105.4
CCPP Unit 8 maximum annual emissions	174.3	48.5	259.1	46.6	112.2
Change in maximum annual emissions	**0**	**0**	**0**	**0**	**(6.8)**

3.4 EL SEGUNDO

The El Segundo Generating Station is located on a 32.8 acre site in El Segundo, California and has been operating as an electric generating station since May 1955. The power plant consists of 4 utility boilers, and associated steam turbines and generators, fired with natural gas and/or refinery gas, although each unit can be fired with fuel oil, if necessary. Current operation uses ocean water for once-through cooling purposes.

The El Segundo Power Redevelopment (ESPR) Project proposes new generating capacity from 2 power block arrangements, each including a gas turbine generator (GTG), a HRSG, and a back pressure steam generator with an ACC for heat rejection. One power block will be designated as Units 5 and 6, and the second as Units 7 and 8. Units 1 and 2 will be demolished and removed from the site and Units 3 and 4 will remain in operation, resulting in a total plant nominal gross generating capacity of the 573 MW. As ACCs will be used for turbine exhaust heat rejection on the new generating units only Units 3 and 4 will use ocean water for once-through cooling.

Water will be supplied to the ESPR Project from two sources: potable water from the Metropolitan Water District of Southern California and reclaimed wastewater from the West Basin Municipal Water District. Potable water will be used for domestic purposes and fire emergencies, whereas reclaimed wastewater will be used as makeup to the steam cycle following additional on-site treatment, and for other generating needs. Process wastewaters from Units 5 – 8 will be recycled, to the maximum extent practical, back to a reclaimed wastewater supply/storage tank to be reprocessed for high purity steam cycle makeup or as makeup for evaporative coolers. No process wastewaters from these units will be discharged from the facility to surface waters. No changes are planned for the management of plant wastes from Units 3 and 4, i.e., these waste streams will be conveyed to an existing retention basin and ultimately discharged through Outfall 002.

Proposed GTGs are a "fast start" technology, which allows the GTGs to reach their optimum air emissions performance operating levels faster, thereby reducing start up emissions. In addition HRSGs will be equipped with SCRs for NOx control and an oxidation catalyst for CO control.

3.5 ENCINA

The Encina Power Station is located on a 95-acre parcel along the southern shore of the Agua Hedionda Lagoon in the City of Carlsbad. The station is a gas fired generating plant with 5 steam turbines (Units 1 – 5), which currently take once-through cooling water from the lagoon. Units 1 – 3 began operation in the 1950s; a small gas turbine generator was also installed in 1968; Unit 4 began operation in 1973; and Unit 5 began operation in 1978, providing a net generating capacity of 966 MW.

The proposed repowering project will include retirement of Units 1, 2, and 3 and construction of two new generating units (Units 6 and 7) to be placed on 30 acres in the northeast portion of the existing facility, between a rail line and Interstate 5, where 3 fuel oil tanks are being removed. Proposed new construction will include a 558 MW combined cycle generating facility using 2 natural gas fired combustion turbine generators (CTGs), 2 HRSGs, and 2 steam turbine generators (STGs), which will connect to switchyards serving the existing power plant. Units 4 and 5 will remain in operation, and with Units 6 and 7, will be known as the Carlsbad Energy Center

The project site is located in an area designated as nonattainment for State and federal air quality standards for ozone, and for PM_{10} and $PM_{2.5}$. Potential impacts to air quality from the repowering project will be mitigated with the installation and operation of Best Available Control Technology (BACT) on the new gas turbines. Retirement of existing Units 1, 2, and 3 will also be used to offset any new emissions.

Water requirements for new generating capacity at the Energy Center will be met by use of reclaimed wastewater supplied by the City of Carlsbad's Water Recycling Facility and potable water also supplied by the City. Approximately 112 acre feet per year of reclaimed wastewater, with maximum possible usage projected at 517 acre feet, will be used for process operations, cooling, on-site irrigation, and miscellaneous water requirements, thereby conserving higher quality local groundwater for other uses. The new generating units will be air cooled, thereby significantly reducing use of ocean water at the facility for once-through cooling. Potable water will be used for domestic purposes, fire protection, and as a backup to the reclaimed wastewater supply. A 3,600 foot reclaimed wastewater pipeline will be installed between the Energy Center and an existing reclaimed wastewater pipeline at Cannon Road and Avenida Encinas. High purity steam cycle make up water will be produced by further treatment of reclaimed wastewater using reverse osmosis and ion exchange technology at the Energy Center.

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