This section is provides a detailed project description of the proposed Chevron Richmond Refinery (Refinery) Power Plant Replacement Project (PPRP, or the Project) to be located in the City of Richmond, California. The design and operation of the proposed project, associated electric transmission lines, natural gas supply line, and water lines are presented here, while site selection and alternative sites considered are presented in Section 9.0, Alternatives.

Section 2.1 provides a description of the generating facility, its design, and its proposed operation. Section 2.2 discusses the safety design of the facility. Section 2.3 describes the expected facility reliability.

### 2.1 Generating Facility Description, Design, and Operation

Chevron proposes to add an additional cogen train (Cogen 3000) and a third-party installed, owned, and operated extraction, condensing steam turbine generator system (H₂-STG) at its Richmond Refinery. The Cogen 3000 will be located on an existing previously developed site within the existing 5.2-acre cogeneration area of the Richmond Refinery. The new H₂-STG will be installed as part of and be located in a new hydrogen production plant being installed by third-party owner, Praxair. The hydrogen plant is also situated within the heart of the existing Refinery.

The Refinery is located along the western edge of the city of Richmond, in Contra Costa County, California, at 841 Chevron Way (See Figure 2.1-1). The approximately 2,900-acre Refinery occupies most of the Point San Pablo Peninsula with east and south boundaries near the residential communities of North Richmond and Point Richmond, respectively. The Refinery is located west of Castro Street and mostly to the north of Interstate 580 (I-580). Castro Street provides access to the Refinery through a number of entrances.

The Refinery processes crude oil into a variety of fuel and oil products. In addition to producing motor gasoline, jet fuel, diesel fuel, and lubricating oils, the Refinery also produces industrial fuel oil, liquefied petroleum gas (LPG), sulfur, and feedstocks commonly used in the petrochemical industry. During the lifetime of the Refinery, Chevron has added, replaced, and upgraded facilities to improve safety and reliability, operational efficiency, produce reformulated gasoline in accordance with state and federal requirements, and comply with applicable environmental regulations.

The Refinery’s existing power generation includes two Alstom ABB GT8 combustion turbine generators, a backpressure steam turbine generator, and a motor-generator used in one of the refinery processing units. The Refinery was placed in operation in 1902 and has been in continuous operation, undergoing upgrades over the years, for the past 105 years.

Cogen 3000 will be a nominal 43-megawatt (MW) net power output (at 59 degrees Fahrenheit [°F]) GE Frame 6B combustion turbine generator (CTG), which will have an inlet...
evaporative cooling system to maximize power output from the machine. The CTG exhaust will discharge through a heat recovery steam generator (HRSG) that will be equipped with refinery fuel gas-fired duct burners to provide steam production up to 430,000 pounds per hour (430 thousand pounds per hour [kpph]). Cogen 3000 will connect to the electrical transmission system via existing dual-circuit 115-kilovolt (kV) lines that loop from the existing cogen switchyard (Sub 5) to the refinery main substation, called the Standard Oil Switching Station (SOSS), which is the point of common coupling with the Pacific Gas and Electric (PG&E) existing 115-kV El Sobrante transmission lines. In addition to Cogen 3000, the H2-STG in the new hydrogen plant will be a nominal 17 MW maximum net output. The H2-STG will tie-in to the refinery electrical system at the 12.47-kV level via a 2,000-foot-long onsite interconnection that will connect through the refinery distribution system to the SOSS. The combined net output of the new Cogen 3000 and new H2-STG will be 60 MW.

The Refinery proposes to burn natural gas, medium-Btu gas, or LPG (butane and propane) in the CTG, and refinery fuel gas (RFG) in the HRSG duct burner. Natural gas and medium-Btu gas for the facility will be delivered via existing pipelines. The Refinery currently imports natural gas for energy use at an approximate rate of 90 million cubic feet per day. Natural gas is both a raw material and an energy source for the Refinery. This use rate has remained approximately the same since Chevron implemented its Reformulated Gasoline and Fluid Catalytic Cracker (FCC) Upgrade Project in 1995. Natural gas consumption after implementation of the Refinery Renewal Project, which includes Cogen 3000 among other projects, is expected to remain at this level or be slightly reduced, depending on the size of the facilities actually built and the impact of energy conservation benefits of the proposed Project.

For cooling tower makeup, the H2-STG will use up to 485 acre feet per year (afy) of recycled water provided by the East Bay Municipal Utility District (EBMUD). Cooling water will be cycled in the H2-STG cooling tower approximately 3.5 times. The blowdown will be sent to the refinery wastewater treatment system.

The recycled water will be delivered to the H2-STG cooling tower from an existing recycled water pipeline. Additional in-plant water distribution piping will be added to route the recycled water to the new cooling tower.

For Cogen 3000 cycle makeup, evaporative cooling makeup, and other uses, Cogen 3000 will use approximately 863 afy of refinery-treated (RO plant) water. The refinery-treated water is supplied from EBMUD. This is the same water supply currently serving the existing steam boilers.

Potable water for drinking, safety showers, fire protection, and service water uses will be served from the existing EBMUD potable water system that currently serves the refinery. No additional sanitary wastewater disposal will be required for the PPRP.

### 2.1.1 Site Arrangement and Layout

The site plan on Figure 2.1-2 and typical elevation views on Figures 2.1-3 and 2.1-4 illustrate the location and size of the proposed Cogen 3000 train. The site plan typical elevation views on Figure 2.1-5 illustrate the location and size of the proposed H2-STG and associated equipment. Both sites are located well within the boundaries of the refinery at least 3,000 feet from the closest refinery property line.
The existing cogen plant is paved around all operating and process equipment. The new Cogen 3000 train will also be paved similarly. Any areas that are not paved will have gravel surfacing. The Cogen 3000 train will be located just north of the two existing cogen trains with a maintenance access road between the new train and the existing train.

The Cogen 3000 generator will connect via a new generator step-up transformer (GSU) to the existing 115-kV Substation 5 switchyard. A single-line diagram for Cogen 3000 is shown in Figure 2.1-6. Power from the new train will be transmitted to the SOSS via two existing fully redundant 115-kV transmission lines (Cogen Line #1 and Cogen Line #2). The SOSS is the point of common coupling with the electric utility, PG&E. From the SOSS, power is distributed throughout the refinery via four 115-kV main transmission lines (Line #1, Line #2, Tap #1, and Tap #2). A single-line diagram of the 115-kV distribution system is shown in Figure 2.1-7. The physical layout of the lines, including the towers and poles, is shown schematically in Figure 2.1-8.

The H₂-STG and related equipment will have concrete foundations and stoned areas around them. No paving will be installed in the operating areas. The H₂-STG will be located on the north end, toward the west side of the hydrogen plant site. The cooling tower supporting the STG will be located east of the steam turbine generator (STG) in the hydrogen processing area.

The H₂-STG will connect to new 12.47-kV switchgear to be installed in the new hydrogen plant. The H₂-STG and hydrogen plant single line diagram is shown in Figure 2.1-9. This switchgear will tie-to the existing refinery distribution system via two existing, fully redundant 12.47-kV overhead distribution lines on poles, via two new redundant, approximately 800-foot-long interconnecting cables routed in cable tray on piperack in the hydrogen plant. The two existing distribution lines are approximately 2,000 feet in length and terminate at existing circuit breakers in the existing refinery 12.47-kV switchgear SWGR 36PS-1 at substation 4. SWGR 36PS-1 connects to the refinery 115-kV distribution system via two existing redundant step-up transformers located at Sub 4. The STG inter-tie to the refinery electrical system is shown on Figure 2.1-10.

### 2.1.2 Process Description

Cogen 3000 will consist of one GE Frame 6B CTG equipped with standard diffusion combustors with steam injection for nitrogen oxide (NOₓ) control; one HRSG with duct burners; a deaerator; evaporative cooling for inlet conditioning of the CTG; and associated support equipment providing a nominal generating capacity of 43 MW net (at average annual ambient conditions of 60°F, 59 percent relative humidity, with duct burners in operation. The CTG exhaust gases will be used to generate steam in the HRSG. The HRSG will be a two-pressure design with duct firing. Steam from the HRSG will be fed into the existing 850 pounds per square inch gage (psig) refinery steam supply header at the cogen plant. The project is expected to have an overall annual availability of 96 to 98 percent.

The Cogen 3000 base load operation heat balance is shown on Figure 2.1-11. This balance is based on an ambient dry bulb temperature of 60°F (annual average), an ambient wet bulb temperature of 53°F (annual average), with duct burners and inlet evaporative cooling in operation. In addition, Figure 2.1-12 shows the heat balance at maximum temperature
(105°F dry bulb), and Figure 2.1-13 shows the heat balance at minimum temperature (35°F dry bulb).

Associated Cogen 3000 equipment will include emission control systems necessary to meet the proposed emission limits. NOx emissions will be controlled at the stack to 2.5 parts per million by volume, dry basis (ppmvd), corrected to 15 percent oxygen by a combination of water-injected diffusion combustors in the CTGs and a selective catalytic reduction (SCR) system in the HRSG. An oxidation catalyst will be installed in the HRSG to limit stack carbon monoxide (CO) emissions to 4.0 ppmvd. VOC emissions will also be limited to 2 ppmvd, corrected to 15 percent oxygen.

The H2-STG will consist of a condensing, extraction, axial discharge steam turbine; a surface condenser; a four-cell mechanical-draft cooling tower; and associated support equipment providing a nominal maximum net generating capacity of 17 MW output at average ambient conditions. The hydrogen production process is exothermic and is a net producer of steam (although a portion of the steam is reused in the production process). At the optimal efficiency point, the STG will receive 930 psig steam from the hydrogen plant steam header and will return a nominal 226 kpph of 535 psig process steam back to the hydrogen plant process via an extraction port. The remainder of the steam will be passed through the low pressure section of the STG for power generation and condensed in the surface condenser. At these steam flow rates the STG will produce 14 MW net output. The surface condenser will utilize approximately one-half of the capacity of the four-cell, mechanical-draft cooling tower for condensing water. The balance of the cooling tower capacity will be used for cooling other non-power generation related hydrogen plant loads.

Figure 2.1-14 shows a simplified flow diagram referencing heat and mass balance information provided on Figure 2.1-15. These figures show the heat balances for a hot day (ASHRE 1% − 85°F DB), average day (60°F DB), and cold day (ASHRE 1% − 43°F). The heat balances show the steam flows to the STG and extraction rates at the optimum STG operating point. Figure 2.1-18 shows the average water balance for the H2-STG.

2.1.3 Generating Facility Cycle

In the CTG of Cogen 3000, combustion air flows through the evaporative cooling media, the inlet air filters, associated air inlet ductwork, and is compressed in the gas turbine compressor section. High-pressure compressed air then flows to the CTG combustor. Natural gas, medium Btu gas, or vaporized LPG (butane with minor amount of propane) fuel is injected into the compressed air in the combustor and ignited. The hot combustion gases expand through the high pressure and low pressure power turbine sections of the CTG, causing the shaft to rotate and drive the electric generator and CTG compressor section. The hot combustion gases exit the turbine at approximately 1,020°F and enter the HRSG. The HRSG is equipped with a duct burner so that supplemental heat can be provided when additional steam production is needed. In the HRSG, boiler feedwater is converted to superheated steam and delivered to the refinery steam systems at two pressures: high pressure (HP) and low pressure (LP). The use of two steam delivery pressures increases cycle efficiency and flexibility. Steam exiting the LP section of the HRSG is supplied to the refinery 30 psig steam header for use in deaerator heating and for other refinery LP steam loads.
In the H₂-STG, high-pressure steam generated in the hydrogen production process expands through the HP section of the steam turbine. A portion of the expanded HP steam is extracted part way through the turbine at 535 psig. The extracted steam is supplied back to the hydrogen plant to enter into the hydrogen production process. The balance of the steam in the STG after extraction is then expanded through the remainder of the steam turbine. Steam leaving the STG exhaust enters the surface condenser where it is condensed. The heat energy of the condensing steam transfers to a circulating water loop, which, in turn, exhausts heat to the atmosphere by means of the mechanical-draft cooling tower.

### 2.1.4 Combustion Turbine Generators, Heat Recovery Steam Generators, Steam Turbine Generator, and Condenser

Electricity is produced by the CTG and the H₂-STG. The following sections describe the major components of the two generating systems.

#### 2.1.4.1 Combustion Turbine Generator

Thermal energy is produced in the CTG through the combustion of gaseous fuel, which is converted into mechanical energy required to drive the combustion turbine compressor and electric generator. One General Electric Frame 6B CTG has been selected for the PPRP.

The CTG system consists of a stationary combustion turbine generator, supporting systems, and associated auxiliary equipment. The Frame 6B is a single-shaft heavy-duty industrial gas turbine.

The major engine components of the Frame 6B are:

- 17-stage compressor
- 10 combustion chambers
- 3-stage air-cooled turbine
- Main speed reduction gear box
- Electrical generator

The gas turbine has a 17-stage compressor, the design of which is based on earlier successful General Electric gas turbine compressors. The compressor rotor consists of individual discs for each stage, which are connected by through bolts. In the compressor, air is compressed in stages by a series of alternate rotating (rotor) and stationary (stator) airfoil shaped blades. Compressed air is extracted from the compressor for turbine cooling, for bearing sealing, and for compressor pulsation control during startup and shutdown. One row of stator blades (inlet guide vanes) is variable to aid in limiting the air flow during startup and to improve the part load efficiency of combined-cycle plants.

The combustion system is of the reverse-flow type and consists of canted combustion chambers arranged around the periphery of the compressor discharge casing. This system also includes the fuel nozzles, spark plug ignition system, flame detectors, and crossfire tubes. Hot gases, generated from burning fuel in the combustion chambers, are used to drive the turbine. High-pressure air from the compressor discharge is directed around the transition pieces and into the annular spaces that surround each of the 10 combustion chamber lines. This air enters the combustion liners through small holes and slots that cool the liner, and through other holes that control the combustion process. Fuel is supplied to
each combustion chamber through a nozzle designed to disperse and mix the fuel with the proper amount of combustion air within the liner. Each combustion chamber is equipped with a fuel nozzle, which performs the functions of metering and injection. Gaseous fuel is admitted directly into each combustion chamber through the calibrated holes of the nozzle cap.

Thermal NOx is generated in the primary zone of the combustion liner where the temperature is higher than 1,800 degrees Celsius (°C). The NOx generation is tightly linked to the temperature and any slight temperature drop involves a significant decrease of the NOx without affecting the combustion efficiency. Steam injection is provided in the liner to reduce the temperature in the primary zone. The injection rate (steam-to-fuel ratio) is a function of the requested reduction of the NOx emission level. Increased steam injection affects the gas turbine performances as follows:

- Increases turbine output
- Increase of the turbine efficiency (decrease of the heat rate)
- Increases the production of CO from the combustor

The turbine rotor consists of three stages, with one wheel for each stage. The turbine rotor wheels are assembled by through bolts similar to the compressor, and with two spacer pieces: one between the first and second stage wheels, the other between the second and third stage wheels. The entire rotor assembly is supported by two bearings.

All turbine stages utilize precision-cast, segmented nozzles, which are supported from the stationary shrouds. This arrangement removes the hot gas path from direct contact with the turbine shell. The turbine stages also have precision-cast, long-shank buckets and this feature effectively shields the wheel rims and bucket dovetails from the high temperatures of the main gas stream.

The gas turbine unit casings and shells are split and flanged horizontally for convenience of disassembly. Compressor discharge air is contained by the discharge casing and turbine shell. The 10 combustion casings are mounted from the discharge casing.

The CTG will be equipped with the following required accessories to provide safe and reliable operation:

- Inlet air filters
- Inlet air evaporative cooling
- Metal acoustical enclosure
- Lube oil cooler
- Diffusion combustion system equipped with steam injection for NOx control
- Compressor wash system
- Fire detection and protection system

The metal acoustical enclosure, which contains the CTG and accessory equipment, will be located outdoors.

2.1.4.2 Heat Recovery Steam Generator

The HRSG provides for the transfer of heat from the exhaust gases of the CTG to the feedwater, which is turned into steam. Major components of the HRSG include a feedwater
heater, an LP evaporator, LP steam drum, HP economizer, HP evaporator, HP separator, and HP superheater.

The feedwater heater receives, via the condensate pumps, a mixture of makeup water from the existing refinery reverse osmosis (RO) plant and return condensate from the refinery process. From the feedwater heater, the condensate is directed to the deaerator where it is stripped of oxygen and other non-condensable gases. Additional steam is fed to the deaerator as needed to heat the water for proper non-condensable stripping. The hot deaerated water exiting the deaerator is fed to the LP evaporator and the HP economizer. The feedwater heater is the final heat transfer section to receive heat from the combustion gases prior to exhausting them to the atmosphere, and providing a lower temperature water to it via incoming makeup before heating in the deaerator allows more of the exhaust gas heat to be captured in the HRSG instead of being wasted up the stack and simultaneously reduces the amount of steam needed for heating the feedwater in the deaerator.

The boiler feed pumps draw suction from the deaerator and send the feedwater to the LP evaporator and the HP economizer. Steam from the LP evaporator, at 30 psig, flows into the existing refinery LP steam system header.

High-pressure feedwater flows through the HP economizer to the HP evaporator, and to the HP superheaters prior to exiting the HRSG to flow into the refinery HP steam header. Saturated steam forms in the evaporator tubes as energy from the combustion turbine exhaust gas and auxiliary duct burner is absorbed. The steam bubbles and heated water flow by natural convection from the evaporator tubes into the steam drum. The saturated water is returned from the steam drum by natural circulation to the HP evaporator tubes, while the steam separates in the steam drum and continues on to the HP superheaters. Within the HP superheaters, the temperature of the HP steam is increased above its saturation temperature, or “superheated,” prior to exiting the HRSG.

A duct burner installed in the HRSG will provide additional heat to augment the turbine exhaust heat so that the HRSG is capable of producing the volume of HP steam required by the Refinery. The duct burner will be fired with refinery fuel gas supplied from a fuel gas mixing drum and will be capable of adding sufficient heat to the CTG exhaust stream to enable the HRSG to produce up to 440 kpph of HP steam.

The HRSG will be equipped with an SCR emission control system that uses anhydrous ammonia (which is produced in the refinery processes) in the presence of a catalyst to reduce NOx in the exhaust gases. The catalyst module will be located within the HRSG casing. Ammonia from the refinery anhydrous ammonia system piping will be injected into the CTG exhaust gas stream via a grid of nozzles located upstream of the catalyst module. The subsequent chemical reaction will reduce NOx to nitrogen and water, resulting in an exhaust gas NOx concentration leaving the HRSG stack of no greater than 2.5 ppmvd corrected to 15 percent oxygen.

An oxidation catalyst will also be installed within the HRSG casing to control the concentration of CO in the exhaust gas leaving the HRSG stack to no greater than 4.0 ppmvd corrected to 15 percent oxygen. The oxidation catalyst will also control VOC emissions in the exhaust gas leaving the HRSG stack to no greater than 2.0 ppmvd corrected to
15 percent oxygen. Exhaust from the HRSG will be discharged from a 138.5-foot-tall, 11.9-foot-diameter (inside) exhaust stack.

2.1.4.3 Steam Turbine Generator

The hydrogen steam turbine system will consist of a condensing, extraction STG with gland steam system, lubricating oil system, hydraulic control system, and steam extraction valving.

Superheated steam from the hydrogen plant process heat recovery steam generators at 930 psig will enter the steam turbine through the inlet steam system. The steam will expand through multiple stages of the turbine, imparting rotary force to the turbine shaft and driving the generator. A portion of the steam will be extracted part way through the turbine at 535 psig for use in the hydrogen production process. On exiting the turbine from the axial exhaust, the exhaust steam will be directed into the surface condenser where its latent heat of condensation will be removed by water circulating through tubes in the condenser. The condenser circulating water will be cooled by water from a four-cell mechanical draft cooling tower. Condensed exhaust steam will be pumped from the condenser hotwell back to the hydrogen plant steam generation equipment.

2.1.5 Major Electrical Equipment and Systems

The bulk of the electric power produced by both generators will be utilized in the refinery. At certain times, depending on refinery electrical load and CTG power generation, a small amount of electric power from Cogen 3000 may be exported to the utility grid. A portion of the CTG power will be used within the cogen plant to power auxiliaries such as fuel gas compressor, chiller, pumps and fans, control systems, and general facility loads including lighting, heating, and air conditioning. A small portion will also be converted from alternating current (AC) to direct current (DC), which is used as backup power for control systems and other uses. Transmission and auxiliary uses are discussed in the following sections.

2.1.5.1 AC Power—Transmission

Power will be generated in the cogen plant by Cogen 3000 at 13.8 kV. The Cogen 3000 power will be stepped up by a generator step-up transformer to 115 kV for transmission to the refinery main substation. An overall single-line diagram of the facility’s electrical system is shown on Figure 2.1-6. The CTG generator will be connected by non-segmented bus duct to 13.8-kV switchgear and from there via solid dielectric underground cable to the oil-filled step-up transformer that increases the voltage to 115 kV as indicated on the single-line diagram. Surge arresters will be provided at the high-voltage bushings to protect the transformer from surges on the 115-kV system caused by lightning strikes or other system disturbances. The transformer will be set on a concrete pad that will be supported on existing pilings that were installed during a previous switchyard upgrade. The high-voltage side of the step-up transformer will be connected to a ring bus in the plant’s existing 115-kV open-air cogen substation (Substation 5). From Substation 5, power will be transmitted via two redundant 115-kV transmission lines (Cogen #1 and Cogen #2) to the SOSS. In order to handle with full redundancy, the additional power that will be generated at the cogen facility, Cogen #1 and Cogen #2 will be upgraded in capacity by reconductoring them with composite core compact aluminum conductor (type ACCC TW).
Power will be generated in the hydrogen plant by the STG at 12.47 kV. The STG will connect via a generator output breaker to 12.47-kV Bus #3, rated at 1,200 amps. Bus #3 will connect from one end via circuit breakers to 12.47-kV Bus #1 and from the other end via circuit breakers to 12.47-kV Bus #2 in the hydrogen plant. These busses are part of the hydrogen plant electrical distribution system. The 12.47-kV busses #1 and #2 will each connect by insulated cable to existing refinery 12.47-kV switchgear located at existing Substation 4. The power cable will be routed aboveground, part way in cable tray on piperack, then transitioned to an overhead line to an existing pole-mounted cable run. The only new portion of these two transmission line runs will be an approximate 800-foot section located within the hydrogen plant and running in a new cable tray. The 12.47-kV switchgear at Substation 4 ties-in to the refinery 115-kV system through two existing step-up transformers at Substation 4. Substation 4 connects back to the SOSS via 115-kV lines No. 1 and No. 2, which are fully redundant.

Power generated by the STG will be mostly consumed within the hydrogen plant. Under some operating conditions there may be up to 3.2 MW excess generation that will feed the refinery distribution system. In situations where the STG is shut down, power will flow from Substation 4 into the hydrogen plant switchgear where it will be distributed to the hydrogen plant loads.

2.1.5.2 AC Power—Distribution to Auxiliaries

Auxiliary power to the Cogen 3000 train will be supplied at 2.4-kV AC by a double-ended 2.4-kV switchgear lineup and at 480-volt AC by a double-ended 480-volt switchgear lineup. Four oil-filled, auxiliary step-down transformers, two at 13.8 kV to 2.4 kV, and two at 13.8 kV to 480 volts will supply primary power to the switchgear in a redundant configuration. The high-voltage side (13.8 kV) of the unit auxiliary transformers will be connected to the output of the CTG via a 13.8-kV switchgear lineup. This connection will allow the switchgear to be powered from the CTGs or from the 115-kV switchyard by back-feeding power through the generator step-up transformer. A 13.8-kV generator circuit breaker will be provided for the generator. This circuit breaker is used to isolate and synchronize the generator, and will be located in the 13.8-kV switchgear adjacent to the CTG enclosure. The 13.8-kV switchgear will be an arc-resistant design to provide a high level of safety against arc flash incidents.

The 2.4-kV switchgear lineup will supply power to the various 2.4-kV motors via a 2.4-kV motor control center. The switchgear will be of arc-resistant design and have vacuum interrupter circuit breakers for the main incoming feeds and for power distribution.

The 480-volt load center transformers will be liquid-filled and supply 480-volt, 3-phase power to each end of the double-ended load center and MCC. Two feeds from the 480-volt switchgear will supply 480-volt power to the 480-volt MCC of the CTG for operation of the CTG auxiliaries.

The 480-volt MCCs will distribute power to 480-volt motors, to 480-volt power distribution panels, and lower voltage lighting and distribution panel transformers. Power for the AC power supply (120-volt/208-volt) system will be provided by the 480-volt MCCs and 480-volt power panels. 480-120/208-volt dry-type transformers will provide transformation of 480-volt power to 120/208-volt power.
For the H₂-STG, auxiliary power will be supplied at 4,160 volts by a triple-fed 4,160-volt switchgear lineup and at 480 volts AC by a triple-fed 480-volt MCC lineup. One feed to the 4,160-volt switchgear will be from 12.47-kV Bus #3 via a 12.47-kV to 4,160-volt stepdown transformer. The other two feeds will be from the two other 4,160-volt busses in the hydrogen plant, each fed by their own separate 12.47-kV to 4,160-volt stepdown transformer.

The Bus #3 4,160-volt switchgear lineup supplies power to the various 4,160-volt motors associated with the STG and cooling tower, via a 4,160-volt motor control center. The switchgear will have vacuum interrupter circuit breakers for the main incoming feeds.

The 480-volt load center transformer will be liquid-filled and supply 480-volt, 3-phase power to one feed of the triple-fed load center and MCC. The transformer will be fed from 4,160-volt bus #3. The other two feeds to 480-volt Bus #3 are from the two other 480-volt busses in the hydrogen plant, each fed by their own separate 4,160-volt to 480-volt stepdown transformers from their respective 4,160-volt busses (4,160-volt Bus #1 and Bus #2). The Bus #3 480-volt MCC lineup also supplies power to the various 480-volt motors associated with the STG and cooling tower, via a 480-volt MCC.

2.1.5.3 125-Volt DC Power Supply System

For the Cogen 3000, one common 125-volt DC power supply system consisting of one 100-percent-capacity battery bank, two 100-percent-capacity static battery chargers, a switchboard, and two or more distribution panels will be supplied for balance-of-plant equipment. The CTG will be provided with its own separate battery system and redundant chargers.

Under normal operating conditions, the battery chargers will supply DC power to the DC loads. The battery chargers will receive 480-volt, three-phase AC power from the AC power supply (480-volt) system and continuously charge the battery banks while supplying power to the DC loads.

Under abnormal or emergency conditions, when power from the AC power supply (480-volt) system is unavailable, the batteries will supply DC power to the DC system loads. Recharging of a discharged battery will occur whenever 480-volt power becomes available from the AC power supply (480-volt) system. The rate of charge will depend on the characteristics of the battery, battery charger, and the connected DC load during charging. The anticipated maximum recharge time will be 12 hours.

The 125-volt DC system will be used to provide control power to the 2,400-volt switchgear, the 480-volt circuit breakers, critical control circuits, and emergency DC motors.

For the H₂-STG, one common 125-volt DC power supply system consisting of one 100-percent-capacity battery bank, one 100-percent-capacity static battery charger, and a distribution panel will be supplied for STG equipment. The three hydrogen plant switchgear buildings will have similar DC supply systems that supply the hydrogen plant DC loads.

Under normal operating conditions, the STG battery charger supplies DC power to the STG DC loads. The battery charger receives 480-volt, three-phase AC power from the AC power
supply (480-volt) system and continuously charge the battery banks while supplying power to the DC control power loads.

Under abnormal or emergency conditions, when power from the AC power supply (480-volt) system is unavailable, the batteries supply DC power to the DC system loads. Recharging of a discharged battery occurs whenever 480-volt power becomes available from the AC power supply (480-volt) system. The rate of charge depends on the characteristics of the battery, battery charger, and the connected DC load during charging. The anticipated maximum recharge time will be 12 hours.

The remaining three 125-volt DC system will be used to provide control power to the 12.47-kV switchgear, and to the 4,160-volt switchgear.

2.1.5.4 **Uninterruptible Power Supply System**

**Cogen 3000 Electrical Systems**

The Cogen 3000 electrical systems will have an essential service 120-volt AC, single-phase, 60-hertz (Hz) uninterruptible power supply (UPS) to supply 120 VAC power to essential instrumentation, critical equipment loads, and unit protection and safety systems that require uninterruptible AC power.

Redundant UPS inverters will supply 120-volt AC single-phase power to the UPS panel boards that supply critical AC loads. The UPS inverters will be fed from the station 125-volt DC power supply system. Each UPS system will consist of one full-capacity inverter, a static transfer switch, a manual bypass switch, an alternate source transformer, and two or more panelboards.

The normal source of power to the system will be from the 125-volt DC power supply system through the inverter to the panelboard. A solid-state static transfer switch will continuously monitor both the inverter output and the alternate AC source. The transfer switch will automatically transfer essential AC loads without interruption from the inverter output to the alternate source upon loss of the inverter output.

A manual bypass switch will also be included to enable isolation of the inverter for testing and maintenance without interruption to the essential service AC loads.

The distributed control system (DCS) operator stations will be supplied from the UPS. The continuous emission monitoring (CEM) equipment, DCS controllers, and input/output (I/O) modules will be fed using either UPS or 125-volt DC power directly.

**H₂-STG Electrical Systems**

The H₂-STG electrical systems will have an essential service 480-volt AC input, single-phase, 60-Hz UPS to supply 120 VAC power to essential instrumentation and critical equipment loads and to unit protection and safety systems that require uninterruptible AC power.

UPS inverters will supply 208-volt AC three-phase power to the UPS panel boards that supply 120 VAC to critical AC loads. The UPS inverters will be fed from the station 125-volt DC power supply system. Each UPS system will consist of one full-capacity inverter, a static transfer switch, a manual bypass switch, an alternate source transformer, and two or more panelboards.
The normal source of power to the system will be from the 125-volt DC power supply system through the inverter to the panelboard. A solid-state static transfer switch will continuously monitor both the inverter output and the alternate AC source. The transfer switch will automatically transfer essential AC loads without interruption from the inverter output to the alternate source upon loss of the inverter output.

A manual bypass switch will also be included to enable isolation of the inverter for testing and maintenance without interruption to the essential service AC loads.

The DCS operator stations will be supplied from the UPS. The CEM equipment, DCS controllers, and I/O modules will be fed using 120 VAC power provided from the UPS.

### 2.1.6 Fuel System

The CTG will be designed to burn natural gas, medium Btu gas, or vaporized LPG. The HRSG duct burner will use refinery fuel gas (RFG) as a fuel. RFG is a blend of refinery hydrocarbon gases, generated as a result of the refining process, which has a varying composition of the gases depending on refinery operating conditions. The CTG fuel requirement during base load operation at annual average ambient temperature will be approximately 463 million British thermal units per hour (MMBtu/hr) (LHV basis). The fuel requirement for the HRSG under medium steam production conditions will be approximately 190 MMBtu/hr (LHV basis). The maximum fuel requirement, experienced during low ambient temperature operation, and full duct firing will be approximately 490 MMBtu/hr (LHV basis) for the CTG and 294 MMBtu/hr (LHV basis) for the HRSG duct burner.

The Refinery imports natural gas at an approximate rate of 90 million cubic feet per day. Natural gas is a raw material for the Refinery and this use rate has remained approximately the same since Chevron implemented its Reformulated Gasoline and FCC Upgrade Project in 1995. Natural gas and medium Btu gas for the CTG will be tapped-off existing headers in the cogen plant main pipe rack to feed the CTG. The gas from the headers will be supplied at a pressure of 350 to 400 psig and will be directed to the CTG combustors.

Refinery fuel gas for the HRSG duct burner will come from an existing RFG header in the cogen area. A new mixing drum will be added at the cogen plant to feed RFG to the Cogen 3000 HRSG duct burners.

### 2.1.7 Water Supply and Use

This section describes the quantity of water required, the sources of the water supply, and water treatment requirements. Two Cogen 3000 water balance diagrams are included, representing two operating conditions. Figures 2.1-16 and 2.1-17 represent: (1) annual average operation at 60°F with the CTG operating at 100 percent load and CTG inlet evaporative cooling in operation, and (2) peak average daily operation at 85°F ambient with the CTG operating at 100 percent load and CTG inlet evaporative cooling in operation.

At average maximum temperature (85°F) Cogen 3000 will use up to 8 gallons per minute (gpm) of water for evaporative cooling makeup, and will use an average of approximately 3 gpm at the annual average ambient temperature (60°F). Cogen 3000 will utilize 532 gpm of
steam cycle makeup water at max steam production levels. The water will be provided by the existing refinery RO plant.

The H2-STG will use up to 300 gpm of recycled water for cooling tower markup. Total recycled water use by the cooling tower would be approximately 480 afy. The recycled water will be delivered to the H2-STG through an existing onsite recycled water header. The H2-STG will use a small amount (approximately 15 gpm) of cycle makeup water to makeup up for gland seal leakage. The cycle makeup will be provided by the existing refinery RO plant.

Potable water will be provided to the PPRP from existing potable water lines currently serving the Refinery. It will be used by the PPRP for safety showers and service water. It will also serve as an emergency water supply, should the recycled water be unavailable for more than 8 hours.

EBMUD is planning to build a treatment plant at the Refinery to treat recycled water to a level that will allow it to serve as boiler makeup water. The plant will contain microfiltration, ultra-filtration, and reverse osmosis. Once this plant comes on-stream, its effluent will displace the current water feed (potable) to the refinery RO plant. The RO plant water is the same water source used by the existing steam boiler plant that will be shut down as part of the PPRP. The new source of purified recycled water is expected to reduce the refinery’s consumption of potable water by 3 to 5 million gallons per day (mgd) when it comes on-stream. However the on-stream date for the EBMUD plant is still uncertain as the project has been recently approved.

No additional sanitary wastewater will be produced as a result of the PPRP.

A more detailed description of the water supply system, treatment, and permits is provided in Section 8.15, Water Resources.

**2.1.7.1 Water Requirements**

A breakdown of the estimated average daily quantity of water, required for operation of the PPRP is presented in Table 2.1-1. The daily water requirements shown are estimated quantities at an ambient temperature of 60°F (annual average dry bulb temperature) based on the H2-STG and Cogen 3000 operating at full load, with the inlet evaporative cooling of the Cogen 3000 CTG. Peak water requirements shown in Table 2.1-1 are based on the plants operating at full load, with evaporative cooling of the CTG inlet air, at an ambient temperature of 85°F (1 percent exceedance dry bulb temperature based upon ASHRAE). Note that the consumption of potable water by the existing steam plant, which will be shut down after PPRP is online, averages 800 gpm or 1,290 afy, which is all fresh water from EBMUD (via the RO plant).
### TABLE 2.1-1
Average Daily, Maximum Daily, and Maximum Annual Water Usage and Wastewater Discharge for the PPRP

<table>
<thead>
<tr>
<th>Water Use</th>
<th>Average Daily Use (gpm)</th>
<th>Maximum Daily Use (gpm)</th>
<th>Maximum Annual Use (afy)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cogen evap cooler makeup a</td>
<td>3</td>
<td>8</td>
<td>5.3</td>
</tr>
<tr>
<td>Cycle makeup water a</td>
<td>532</td>
<td>540</td>
<td>944</td>
</tr>
<tr>
<td>H2-STG cooling tower makeup b</td>
<td>300</td>
<td>330</td>
<td>532</td>
</tr>
<tr>
<td>Potable water service</td>
<td>3</td>
<td>10</td>
<td>4.9</td>
</tr>
<tr>
<td>Wastewater discharge</td>
<td>90</td>
<td>105</td>
<td>145</td>
</tr>
</tbody>
</table>

a Evaporative cooler and cycle makeup water will come from recycled water after the RARE plant is operational at some future as yet undetermined date

b H2-STG cooling tower makeup will come from recycled water

#### 2.1.7.2 Water Supply

During normal operation, approximately 36 percent of the total PPRP water demand will be for cooling tower makeup water to replace water lost to evaporation. The remaining water demands will include process cycle makeup, plant service water, and potable water for domestic uses. A detailed description of the water supply is presented in Section 8.12.

#### 2.1.7.3 Water Treatment

Water use can be divided into the following four levels based on the quality required: (1) water for the circulating (or cooling) water system; (2) service water for the plant, which will include all other miscellaneous uses; (3) RO water for makeup to the steam cycle; and (4) potable water. Water treatment required to obtain these four levels of quality is described in the following paragraphs.

**Water for the Circulating Water System**

Recycled water will be fed from the existing refinery recycled water pipeline into the H2-STG cooling tower basin as required to replace water lost to evaporation, drift, and blowdown.

To minimize corrosion and control the formation of mineral scale and biofouling, a chemical feed system will supply water conditioning chemicals to the circulating water. The cooling towers will be operated consistent with industry standards to control biological growth. To prevent biofouling in the circulating water system, sodium hypochlorite will be fed into the system. The hypochlorite feed equipment will consist of a bulk storage tank and two sodium hypochlorite metering pumps. Additional chemical storage and feed systems will be provided for feeding alternate oxidizing and non-oxidizing biocides.

**Service Water**

Service water includes all water uses at the plant except for the circulating water previously discussed, RO water used for makeup to the steam cycle, demineralized water used for injection into the CTG, and potable water. City (potable) water protected by a reduced pressure backflow prevention device or air gap will be used for service water. No additional treatment of the City water will be required for use as service water.
Makeup Water for the Steam Cycle
RO water will be used for makeup water for the steam cycle. RO water will be produced in an existing RO treatment plant that is located near the Cogen facility. The steam cycle makeup water needs will not impose any additional flow requirements on the RO plant because the new PPRP steam supply will be replacing current steam supply equipment that will be shut down after PPRP is in operation. In addition, the RO water, which is currently produced from potable water, will ultimately have recycled water as its feed source once the RARE project is in operation (no projection on when this will occur as the RARE project is currently undergoing review by EBMUD).

To minimize steam cycle corrosion and scale formation, chemical feed systems will feed a neutralizing amine to the condensate for corrosion control and a phosphate solution to the HRSG steam drums for pH control. The design will provide for automatic feed of the amine in proportion to condensate flow with a pH bias. The system will include an amine solution feed tank and two amine feed pumps. The amine system will include a relatively high-volume metering pump to provide sufficient quantities of chemicals to support wet lay-up of the HRSGs during short down-periods.

The phosphate feed system will be designed for operation using the low solids, coordinated phosphate, or other standard method of boiler water treatment. The phosphate feed will be manually initiated based on boiler water phosphate residual and manually biased for pH. One solution tank and one phosphate feed pump will be provided for each LP and HP steam drum with one common spare pump serving each HRSG. Existing chemical storage tanks used for the two existing cogen units will also serve the new PPRP cogen unit.

Potable Water
Potable water for drinking, safety showers, fire protection water, and service water, will be served from the existing refinery potable water service provided by EBMUD.

2.1.8 Plant Cooling Systems
For the H₂-STG, the heat rejection system will consist of a steam surface condenser, cooling tower, and circulating water system. The heat rejection system will receive exhaust steam from the low-pressure section of the steam turbine and condense it back to water for reuse. The surface condenser will be a shell-and-tube heat exchanger with the steam condensing on the shell side and the circulating water flowing in one or more passes inside the tubes. The condenser will be designed to operate at sub-atmospheric pressure, ranging from 0.66 psia to 1.96 psia, depending on ambient temperature and plant load. The condenser will remove heat from the condensing steam up to a maximum of 136.6 MMBtu/hr, depending on ambient temperature and plant load. Approximately 15,720 gpm of circulating cooling water will be used to condense the steam at maximum plant load.

The circulating water will pass through a counter-flow mechanical draft-cooling tower, which uses electric-motor-driven fans to move the air in a direction opposite the flow of the water. The heat removed in the condenser will be discharged to the atmosphere by heating the air and through evaporation of a portion of the circulating water. Drift, the fine mist of water droplets entrained in the warm air leaving the cooling tower, will be limited to 0.002 percent of the circulating water flow.
The cooling tower water system will also provide for cooling plant equipment other than
the steam condenser and vacuum pumps. Equipment served by the cooling water system
will include the STG lube oil coolers, STG hydraulic control system cooler (if required by
STG manufacturer), STG gland seal condenser, generator cooler, boiler feed pump, seal
water coolers, and sample coolers.

For the Cogen 3000 portion of the PPRP, the only heat rejection required will be from
miscellaneous auxiliary coolers, such as the lube oil cooler, and the generator.

An existing closed-loop auxiliary cooling system will be expanded to provide for cooling
plant equipment. Equipment served by the auxiliary cooling water system includes the
CTG oil coolers, boiler feed pump lube oil and seal water coolers, CTG generator, and
sample coolers. Closed-loop cooling water pumps will pump condensate quality water from
the plate heat exchangers through the individual equipment coolers to remove heat. Water
feeding the existing RO plant will be pumped through the heat exchangers to remove heat
from the closed cooling water system. This will also preheat the RO feed water, which
assists in the RO process.

2.1.9 Waste Management

Waste management is the process whereby all wastes produced at the PPRP are properly
collected, treated if necessary, and disposed of. Wastes include process wastewater,
nonhazardous waste, and hazardous waste, both liquid and solid. Waste management is
discussed in more detail in Section 8.13.

2.1.9.1 Wastewater Collection, Treatment, and Disposal

The primary wastewater collection system will collect process wastewater from all of the
plant equipment, including the HRSG, cooling tower, and water treatment equipment. The
water balance diagrams, Figures 2.1-16, 2.1-17 and 2.1-18, show the expected wastewater
streams and flow rates for the PPRP.

The Refinery operates its own wastewater treatment system. The system’s capacity is
approximately 20 mgd, compared to an average May 2003 – September 2004 dry-weather
wastewater discharge of 5.48 mgd. During periods of dry weather such as the summer
months, almost all wastewater comes from the various processing plants. Sources of this
process wastewater include cooling tower blowdown, condensed steam used for process
heating, plant wash-up water, etc. Process wastewater is treated in the Refinery effluent
treatment system prior to release into the Bay.

The effluent wastewater is regulated under a National Pollutant Discharge Elimination
System (NPDES) permit issued by the San Francisco Bay Regional Water Quality Control
Board (RWQCB) (No. CA0005134). The permit identifies 23 distinct wastewater streams
with 10 identified outfalls as well as Chevron’s 38-foot channel, Castro Creek, Wildcat
Creek, and the Gertrude Street ditch. Stormwater from across the Refinery is either directly
discharged through the various outfalls or is commingled with steam condensate,
groundwater seepage, and/or water from fire protection systems. The NPDES permit
provides for optional conditions during periods of high intensity rainfall events.
During the winter months, in addition to the refinery average 5.48 mgd process wastewater, large amounts of rainfall also enter the effluent treatment system. The 2004 daily wastewater flow varied from a low of 0.0 mgd in June to a high of 24.75 mgd in January. This increase in wastewater flow was due principally to the influx of rainfall into the system. Implementation by Chevron of a system that separates stormwater from wastewater has resulted in only the wastewater flow being treated by the wastewater system. As a result, the current system has excess capacity for treating wastewater. The effluent treating system was originally sized to handle simultaneously the full flow of wastewater and stormwater from a large storm.

Chevron discharges stormwater and treated process wastewater, which contains stormwater commingled with steam condensate, firewater, and/or groundwater (and other minor wastewater streams identified in the permit application), to outfalls in the San Francisco and/or San Pablo Bays. The discharge of treated process wastewater is regulated and permitted by the RWQCB. The process wastewater treatment system is segregated into three collection areas, the north yard, the central yard, and the south yard. Each of these collection system areas accepts flows from the process units in their respective area and routes them via three separate oil/water separators to a 165 million gallon biological treatment unit. Temperatures at each of the separators are estimated at 26.7°C (80°F) year round, while temperatures in the bioreactor vary from 26.7°C (80.0°F) in the Aggressive Biological Treatment Area to between 15.6°C (60°F) and 18.3°C (65°F) in the settling basin area.

The Aggressive Biological Treatment Area (bioreactor) has approximately 900 subsurface air aerators supplied by two compressors that deliver approximately 17,000 cubic feet per minute of air to the bioreactor. The aerators supply oxygen for biological treatment and to provide mixing. From the bioreactor treatment segment, there are two options for further effluent treatment. Bioreactor effluent can either be routed directly to the deepwater outfall point sump for discharge to the Bay through the granular activated carbon unit or a portion of the effluent may be routed through the three-tier constructed wetlands, Richmond Refinery Water Enhancement Wetland (RRWEW), for tertiary polishing and selenium removal. Effluent from the wetlands rejoins the main wastewater stream at the deepwater outfall sump and these commingled streams are discharged through the granular activated carbon unit to a 36-inch diffuser outfall at an average depth of 30 to 50 feet into the San Pablo Bay (approximately 2,000 feet offshore to the north of Point San Pablo) in accordance with the Refinery’s NPDES permit.

The RRWEW wetland is a natural treatment and polishing system primarily for solids and metals removal. This system consists of natural filtration carried out in three stages that can contain approximately 30 million gallons of effluent at any given moment. This effluent is supplied from the bioreactor at approximately 1.5 mgd; however, this flow may be increased depending on seasonal conditions and other ecological requirements. The wetland consists of primarily cattails and bulrushes to assist in settling and biotreatment. The flow is supplied to this first stage via a hardpiped system directly from the bioreactor settling area. Effluent from the wetlands is pumped to the deepwater outfall sump to rejoin the remaining water from the bioreactor. Based on a two-year study of the RRWEW between 1994 and 1995 by Chevron, additional management actions were implemented to limit bird exposures
to selenium in the RRWEW food chain. In follow up studies between 2000 and 2004, a significant reduction (up to one-third of 1994 levels) in selenium was observed.

**Circulating Water System Blowdown**
Circulating water system blowdown from the cooling tower will consist of recycled water from EBMUD along with residues of the chemicals added to treat the circulating water. These chemicals control scaling and biofouling of the cooling tower, and control corrosion of the circulating water piping and the condensers. Cooling tower blowdown will be discharged to the Refinery wastewater treatment system.

**Plant Drains and Oil/Water Separator**
General plant drains will collect containment area washdown, sample drains, and drainage from facility equipment drains. Water from these areas will be collected in a system of floor drains, hub drains, sumps, and piping and routed to the wastewater collection system. Drains that potentially could contain oil or grease will first be routed through an existing oil/water separator.

**Cogen Cycle Makeup Water Treatment Wastes**
Distillate from the existing refinery RO system will be used as the feed water for the cycle makeup treatment system. Since this distillate is already very low in total dissolved solids (TDS), the cycle makeup treatment system will require no further treatment and thus no treatment waste will be generated.

**HRSG Blowdown**
HRSG blowdown will consist of boiler water discharged from the HRSG LP and HP steam drums to control the concentration of dissolved solids and silica within acceptable ranges. HRSG blowdown will ultimately be discharged to flash tanks where the flash steam is sent to lower pressure refinery steam systems and the condensate is cooled by cooling water in a heat exchanger. The cooled condensate will then be forwarded to one of the other refinery process units for use in that process.

**2.1.9.2 Solid Wastes**
The PPRP will produce maintenance and plant wastes typical of power generation operations. Generation plant wastes include oily rags, broken and rusted metal and machine parts, defective or broken electrical materials, empty containers, and other solid wastes, including the typical refuse generated by workers. The Refinery currently generates approximately 37,000 cubic yards of non-hazardous solid waste per year, all of which is in the form of Class III trash for disposal at the West Contra Costa Landfill. This waste is managed in large bins and is currently removed from the Refinery by Richmond Sanitary Service.

The Refinery has a Waste Minimization Plan, and makes continuing efforts to reduce the amount of solid hazardous and non-hazardous waste generated. Pre-job planning to reduce the amount of soil requiring disposal, source reduction of solids, and testing and segregation of hazardous wastes with a focus on recycling are ongoing activities in the Refinery. In addition, the Refinery has emphasized a paper reduction program to eliminate unnecessary reports and copies of printed material. It also segregates paper and cardboard products for recycling.
2.1.9.3 Hazardous Wastes

Several methods will be used to properly manage and dispose of hazardous wastes generated by the PPRP. Waste lubricating oil will be either recovered and recycled by the Refinery or disposed of in accordance with regulatory requirements. Spent SCR and oxidation catalysts will be recycled by the supplier. The Refinery has a well-established, well-documented, and effective hazardous waste handling and management system that is used to collect, categorize, store and dispose of hazardous waste. This system will be utilized to deal with any hazardous wastes generated during construction or operation of the PPRP.

2.1.10 Management of Hazardous Materials

There will be a variety of chemicals stored and used during construction and operation of the PPRP. The storage, handling, and use of all chemicals will be conducted in accordance with applicable LORS. Chemicals will be stored in appropriate chemical storage facilities. Bulk chemicals will be stored in storage tanks, and most other chemicals will be stored in returnable delivery containers. Chemical storage and chemical feed areas will be designed to contain leaks and spills. Berm and drain piping design will allow a full-tank capacity spill without overflowing the berms. For multiple tanks located within the same bermed area, the capacity of the largest single tank will determine the volume of the bermed area and drain piping. Drain piping for reactive chemicals will be trapped and isolated from other drains to eliminate noxious or toxic vapors. After neutralization, if required, water collected from the chemical storage areas will be directed to the refinery wastewater collection system.

There will be no anhydrous ammonia storage at the cogen facility since anhydrous ammonia is produced at the refinery and, therefore, can be piped from the existing refinery storage system.

Safety showers and eyewashes will be provided adjacent to or near chemical storage and use areas. Plant personnel will use approved personal protective equipment during chemical spill containment and cleanup activities. Refinery personnel are properly trained in the handling of these chemicals and instructed in the procedures to follow in case of a chemical spill or accidental release. The refinery maintains a fully staffed emergency response organization that is well trained and equipped to deal with any accidental release from the PPRP. This has been documented in the Refinery’s existing Risk Management Plan and California Accidental Release Plan (CalARP).

A list of the chemicals anticipated to be used at the PPRP and their storage locations is provided in Section 8.11.2, Hazardous Materials Handling. This list identifies each chemical by type, intended use, and estimated quantity to be stored onsite. Section 8.11.5 includes additional information on hazardous materials handling.

2.1.11 Emission Control and Monitoring

Air emissions from the combustion of fuels in the CTGs and HRSG duct burner will be controlled using state-of-the-art systems. To ensure that the systems perform correctly, continuous emissions monitoring for NOx and CO will be performed. Section 8.1, Air Quality, includes additional information on emission control and monitoring.
2.1.11.1 NOx Emission Control
The CTG selected for the project includes steam injected diffusion combustors designed to control emissions of NOx to 25 ppm in the CTG exhaust when natural gas or medium Btu gas fuel is used. In addition, the HRSGs will include an SCR system to further control NOx concentrations in the exhaust stacks to 2.5 ppmv. The SCR process will use anhydrous ammonia as a reactant for NOx reduction. Ammonia slip, or the concentration of unreacted ammonia in the HRSG stack exhaust, will be limited to 10 ppmv. The SCR equipment will include a reactor chamber, catalyst modules, ammonia vaporization and injection system, and monitoring equipment and sensors. Ammonia will be supplied from existing ammonia production facilities on site.

2.1.11.2 Carbon Monoxide and Volatile Organic Compound Emission Control
CO and VOC emissions from the CTG and HRSG duct burners will be controlled by means of a CO oxidation catalyst. CO and VOC emission rates in the HRSG stack exhaust will be limited to 4 ppmv and 2 ppmv respectively.

2.1.11.3 Particulate Emission Control
Particulate emissions will be controlled by the use of best combustion practices, the use of low-sulfur fuel, and high efficiency air inlet filtration.

PM10 emissions from the STG cooling tower will be controlled through the use of high-efficiency drift eliminators which reduce the drift to 0.002 percent of the circulating water flow.

2.1.11.4 Continuous Emission Monitoring
For the CTG, CEM equipment will sample, analyze, and record fuel gas flow rate, NOx, and CO concentration levels, and percentage of oxygen in the exhaust gas from the HRSG stacks. The CEM equipment will transmit data to a data acquisition system (DAS) that will store the data and generate emission reports in accordance with permit requirements. The DAS will also include alarm features that will send signals to the plant DCS when the emissions approach or exceed pre-selected limits.

2.1.12 Fire Protection
The fire protection system will be designed to protect personnel and limit property loss and plant downtime in the event of a fire. The source of fire protection water will be the refinery’s fire water system.

The Refinery has an extensive existing fire protection system that is designed to fight any type of fire that may occur within the Refinery. In addition, the Plant Protection Department within the Refinery is fully staffed with qualified and trained personnel and equipment to deal with all types of fires.

In addition to the general refinery fire protection systems, the Frame 6B turbine generator set includes controls to detect fire, unsafe temperatures or explosive atmospheres in the equipment enclosure. The system releases CO2 if a fire is detected within the enclosure.
The CTG package enclosure is designed to reduce the hazard of fire and explosion. A wall separates the turbine and generator compartments to provide isolation. Ventilation systems, with redundant fans, create a positive pressure in the generator compartment and a negative pressure in the turbine compartment. This maintains separation and forces hydrocarbons away from the generator. The enclosure is protected by gas detectors, thermal detectors, optical flame detectors and a CO₂ extinguishing system conforming to NFPA 12.

Three manual trip stations will be located on the main enclosure; one on each side near the center of the package, and the third at the exciter end of the generator.

The CO₂ extinguishing system components will include:

- Main CO₂ storage cylinders
- Reserve CO₂ storage cylinders
- Necessary valves, piping, and wiring

Pressurized CO₂ bottles will be stored on a separate rack that will include manifolds, controls, valves, and a weigh scale. The reserve cylinders will be an “automatic backup,” and will be released, if detectors still indicate a hazard, 90 seconds after release of the main cylinders.

Piping will be provided within the main enclosure from the pressure connection to the nozzles in the turbine and generator compartment. Release of the CO₂ will be controlled by the fire system control panel or by a manual valve at the unit. Signals from the equipment-mounted sensors will be monitored by solid-state modules in the control panel. The panel-mounted unit will include logic, memory, and output functions to complete the system.

A dedicated 24 VDC battery system with charger will be provided to power the fire and gas protection system and control system. This battery system will conform to NFPA 12 requirements.

Section 8.11, Hazardous Materials Handling, includes additional information for fire and explosion risk, and Section 8.7, Socioeconomics, provides information on local fire protection capability.

During construction, the existing refinery fire protection system and emergency response team will be used to deal with any fires. Existing refinery fire protection measures, including the use of fire watches, will be used for fire prevention.

### 2.1.13 Plant Auxiliaries

The following systems will support, protect, and control the generating facility.

#### 2.1.13.1 Lighting

The lighting system will provide personnel with illumination for operation under normal conditions and for egress under emergency conditions, and will include emergency lighting to perform manual operations during an outage of the normal power source. The system will also provide 120-volt convenience outlets for portable lamps and tools.
2.1.13.2 Grounding

The electrical system is susceptible to ground faults, lightning, and switching surges that result in high voltage that constitutes a hazard to site personnel and electrical equipment. The station grounding system will provide an adequate path to permit the dissipation of current created by these events.

The station grounding grid will be designed for adequate capacity to dissipate the ground fault current from the ground grid under the most severe conditions in areas of high ground fault current concentration. The grid spacing will maintain safe voltage gradients.

Bare conductors will be installed below-grade in a grid pattern. Each junction of the grid will be bonded together by an exothermic weld. The new grounding grid will be tied to the existing ground grid by exothermic welding.

Ground resistivity readings will be used to determine the necessary numbers of ground rods and grid spacing to ensure safe step and touch potentials under severe fault conditions.

Grounding conductors will be brought from the ground grid to connect to building steel and non-energized metallic parts of electrical equipment.

2.1.13.3 Distributed Control System

The DCS will provide modulating control, digital control, monitoring, and indicating functions for the plant power block systems.

The following functions will be provided:

- Controlling the STG, CTGs, HRSGs, and other systems in a coordinated manner
- Controlling the balance-of-plant systems in response to plant demands
- Monitoring controlled plant equipment and process parameters and delivery of this information to plant operators
- Providing control displays (printed logs, LCD video monitors) for signals generated within the system or received from I/O
- Providing consolidated plant process status information through displays presented in a timely and meaningful manner
- Providing alarms for out-of-limit parameters or parameter trends, displaying on alarm video monitors(s), and recording on an alarm log printer
- Providing storage and retrieval of historical data

The DCS at the hydrogen plant STG will be a redundant microprocessor-based system and will consist of the following major components:

- PC-based operator consoles with LCD video monitors
- Engineer work station
- Multiple redundant processing units
- I/O cabinets
- Historical data unit
Printers

Data links to the combustion turbine and steam turbine control systems

The DCS will have a functionally distributed architecture comprising a group of similar redundant processing units linked to a group of operator consoles and the engineer workstation by redundant data highways. Each processor will be programmed to perform specific dedicated tasks for control information, data acquisition, annunciation, and historical purposes. By being redundant, no single processor failure can cause or prevent a unit trip.

The Cogen 3000 will utilize the existing cogen facility DCS, which will be expanded to accommodate the additional equipment and monitoring I/O and programming.

The two DCS systems will interface with the control systems furnished by the CTG and STG suppliers to provide remote control capabilities, as well as data acquisition, annunciation, and historical storage of turbine and generator operating information.

The systems will be designed with sufficient redundancy to preclude a single device failure from significantly affecting overall plant control and operation. This also will allow critical control and safety systems to have redundancy of controls, as well as an uninterruptible power source.

As part of the quality control program, daily operator logs will be available for review to determine the status of the operating equipment.

2.1.13.4 Cathodic Protection

The cathodic protection system will be designed to control the electrochemical corrosion of designated metal piping buried in the soil. Depending upon the corrosion potential and the site soils, either passive or impressed current cathodic protection will be provided.

2.1.13.5 Service Air

The existing service air system in the cogen facility will be extended to supply compressed air to hose connections for general plant use. Service air headers will be routed to hose connections located at various points throughout the facility.

For the hydrogen plant STG, service air for hose connections in the STG and cooling tower areas will come from the hydrogen plant instrument air system.

2.1.13.6 Instrument Air

The instrument air system will provide dry air to pneumatic operators and devices. An instrument air header will be routed to locations within the facility equipment areas where pneumatic operators and devices will be located.

2.1.14 Interconnect to Electrical Grid

Cogen 3000 will feed power via existing, onsite Refinery-owned 115-kV transmission lines to the SOSS, which is the point of common coupling with the utility. No new or upgraded offsite transmission lines will be required. However the two existing 115-kV lines between the cogen switchyard (Substation 5) and the main switchyard (SOSS) will be reconductored to provide higher ampacity (see Section 5.0, Electric Transmission). Reconductoring will be
done with a composite-core cable that will provide higher ampacity without an increase in cable weight. Therefore, no changes will be required to transmission towers or foundations.

### 2.1.15 Project Construction

Actual construction of the hydrogen plant STG is planned to take place from the first quarter of 2008 to the first quarter of 2009. Actual construction of Cogen 3000 is planned to take place over approximately 15 months, from second quarter 2008 to first quarter 2010. Plant testing is planned to commence in the first quarter of 2010, and commercial operation is expected to commence no later than the second quarter 2010. Major milestones are listed in Table 2.1-2.

<table>
<thead>
<tr>
<th>Activity</th>
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<tr>
<td>Begin Construction of H2 Plant STG</td>
<td>First Quarter 2008</td>
</tr>
<tr>
<td>Begin Construction of Cogen</td>
<td>Second Quarter 2008</td>
</tr>
<tr>
<td>Startup and Test H2 Plant STG</td>
<td>First Quarter 2009</td>
</tr>
<tr>
<td>Startup and Test Cogen</td>
<td>First Quarter 2010</td>
</tr>
<tr>
<td>Commercial Operation of H2 Plant STG</td>
<td>First Quarter 2009</td>
</tr>
<tr>
<td>Commercial Operation of Cogen</td>
<td>Second Quarter 2010</td>
</tr>
</tbody>
</table>

For the cogen plant, there will be an average and peak workforce of approximately 119 and 181, respectively, of construction craft people, supervisory, support, and construction management personnel onsite during construction. For the hydrogen plant STG project, there will be an average and peak workforce of 14 and 25, respectively, of construction craft people, supervisory, support, and construction management personnel onsite during construction (see Tables 8.7-4 and 8.7-5).

Noisy construction will be scheduled to occur between 6 a.m. and 7 p.m. on weekdays and holidays. Additional hours may be necessary to make up schedule deficiencies, or to complete critical construction activities (e.g., pouring concrete at night during hot weather, working around time-critical shutdowns and constraints). During some construction periods and during the startup phase of the project, some activities will continue 24 hours per day, 7 days per week.

The peak construction site workforce level is expected to last from Month 14 through Month 19 of the construction period.

Table 8.9-6 provides an estimate of the construction traffic during the overall construction period for the entire Renewal Project including the PPRP and associated linear facilities. Peak trip generation is expected in the first quarter of 2008 as summarized in Table 2.1-3.
## TABLE 2.1-3
Traffic Generation Estimates – First Quarter 2008

<table>
<thead>
<tr>
<th>Project</th>
<th>Type</th>
<th>Daily (ADT)</th>
<th>AM Peak Hour (Vehicles/Hour)</th>
<th>PM Peak Hour (Vehicles/Hour)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>In</td>
<td>Out</td>
<td>In</td>
</tr>
<tr>
<td>Construction</td>
<td>Vehicle</td>
<td>1,595</td>
<td>399</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>Trucks</td>
<td>172</td>
<td>86</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>Subtotal</td>
<td>1,767</td>
<td>485</td>
<td>0</td>
</tr>
<tr>
<td>Other Projects</td>
<td>Vehicle</td>
<td>119</td>
<td>30</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>Trucks</td>
<td>24</td>
<td>12</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>Subtotal</td>
<td>143</td>
<td>42</td>
<td>0</td>
</tr>
<tr>
<td>Major Refinery Turnaround</td>
<td>Vehicle</td>
<td>349</td>
<td>87</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>Trucks</td>
<td>24</td>
<td>12</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>Subtotal</td>
<td>373</td>
<td>99</td>
<td>0</td>
</tr>
<tr>
<td>TOTAL</td>
<td></td>
<td>2,283</td>
<td>626</td>
<td>0</td>
</tr>
</tbody>
</table>

Notes:
ADT = Average Daily Traffic
For peak hour trip generation, assume all inbound trips occur during the AM peak hour and all outbound trips occur during the PM peak hour, as shown:
Half of the vehicle trips arrive at 6:00 AM for a 10-hour shift, departing at 4:00 PM
Half of the vehicle trips arrive at 7:00 AM for a 10-hour shift, departing at 5:00 PM
Assume all trucks are inbound in the AM and outbound in the PM
Assume half trucks arrive at 7:00 AM and depart at 3:00 PM, half arrive at 6:00 AM and depart at 2:00 PM.

Due to the large site, accommodation for construction parking/laydown areas will be readily available. Construction laydown and parking areas will occupy about 8.9 acres at various locations around the plant site (see Figure 2.1-19). These sites are active refinery construction laydown areas dedicated for ongoing refinery construction and maintenance activities. Construction access to the plant site will generally be from Castro Street. Materials and equipment will be delivered by truck and rail. Existing railroad spurs are located within the refinery and extensive rail spurs and rail traffic exist outside of the refinery due to the heavy industrialization of the area and the proximity to the Port of Richmond.

### 2.1.16 Generating Facility Operation

Cogen 3000 will be operated by existing cogen and power plant facility operators, therefore, no personnel will be added to the operating, maintenance, or administrative staff for this additional facility. The hydrogen plant STG will be operated by hydrogen plant operators on an 8-hour rotating shift. There will be no operating, maintenance, or administrative staff dedicated to the STG equipment operation.

The PPRP is expected to have an annual plant availability of 98 to 99 percent. It will be possible for plant availability to exceed 98 percent for a given 12-month period. Chevron
expects to operate the PPRP primarily as a base load unit, with some amount of load following. The exact operational profile of the plant, however, cannot be defined in detail since operation of the facility depends on the variable demand in the refinery as well as the future ability and economics associated with exporting power to the grid.

The facility may be operated in one or all of the following modes:

- **Base Load.** The facility would be operated at its maximum continuous output for as many hours per year as the refinery requires. It is anticipated that the facility will operate as a base load unit throughout the summer months to supply, in conjunction with the other generation, all of the refinery’s power needs and to export any available excess power to the utility grid.

- **Load Following.** During non-peak seasons (primarily spring and fall), the facility would be operated at loads that may vary between maximum continuous output (CTG operating with inlet evaporatively cooled) and minimum load (CTG operating with evaporative cooling off and producing as low as 60 to 70 percent of maximum generating capacity to meet the Refinery’s demand at all times of the day.

- **Full Shutdown.** This would occur if forced by equipment malfunction, fuel supply interruption, transmission line disconnect, or scheduled maintenance.

In the unlikely event of a situation that causes a longer-term cessation of operations, security of the facilities will be maintained and appropriate agency notifications will be made in accordance with applicable LORS. Depending on the length of shutdown, a contingency plan for the temporary cessation of operations may be implemented. Such contingency plan will be in conformance with all applicable LORS and protection of public health, safety, and the environment. The plan, depending on the expected duration of the shutdown, could include the draining of all chemicals from storage tanks and other equipment and the safe shutdown of all equipment. All wastes will be disposed of according to applicable LORS. If the cessation of operations becomes permanent, the plant will be decommissioned (see Section 4.0, Facility Closure).

### 2.2 Facility Safety Design

The PPRP will be designed to maximize safe operation. Potential hazards that could affect the facility include earthquake, flood, and fire. Facility operators will be trained in safe operation, maintenance, and emergency response procedures to minimize the risk of personal injury and damage to the plant.

#### 2.2.1 Natural Hazards

The principal natural hazard associated with the PPRP site is earthquakes. The site is located in Seismic Risk Zone 4. Structures will be designed to meet the seismic requirements of CCR Title 24 and the 2007 California Building Code (CBC) (See Section 8.13, Geologic Resources and Hazards). This section includes a review of potential geologic hazards, seismic ground motion, and potential for soil liquefaction due to ground-shaking. Potential seismic hazards will be mitigated by implementing the 2007 CBC construction guidelines.
Flooding of the project sites is not considered to be a probable hazard. The vast majority of the Refinery operations are outside the 100-year floodplain although the property boundary includes areas that are within the 100-year floodplain (ESRI-FEMA, 2001). All of the Proposed Project elements would be located outside the 100-year floodplain. Section 8.15, Water Resources, includes additional information on the potential for flooding.

2.2.2 Emergency Systems and Safety Precautions

This section discusses the fire protection systems, emergency medical services, and safety precautions to be used by project personnel. Section 8.7, Socioeconomics, includes additional information on area medical services, and Section 8.6, Public Health, includes additional information on safety for workers. Compliance with these requirements will minimize project effects on public and employee safety.

2.2.2.1 Fire Protection Systems

The project will rely on onsite fire protection systems and fire protection personnel. The Chevron Refinery maintains an emergency response program designed to protect worker and public safety, as well as the environment. As part of the Emergency Response Program, there is a written plan for responding to accidental chemical releases, including procedures for notifying the public and local emergency response agencies. The program also includes the maintenance, inspection, and testing of emergency response equipment.

The Chevron Refinery has emergency response teams that are trained and equipped to respond to fires, rescues, hazardous material releases, and other emergencies that could occur at the Refinery. These teams are managed by the Supervisor of Fire Protection, whose responsibility it is to ensure that the Emergency Response Plan is implemented and followed in the preparation for, and response to plant emergencies.

As part of the Emergency Response Program, the Chevron Richmond Refinery works with local emergency responders in preparing for and responding to emergencies. This includes conducting emergency drills with the Richmond Fire Department and/or Contra Costa County Health Services on potential fires and/or hazardous materials releases.

The Chevron Refinery is a member of an industrial mutual aid organization, the Petrochemical Mutual Aid Organization (PMAO), and has responded to emergencies at other oil facilities and chemical plants that are members of the PMAO. The Refinery also provides assistance to the City of Richmond Fire Department for events outside of the Refinery when requested by the City Fire Department.

The extensive refinery fire protection systems are designed to protect personnel and limit property loss and plant downtime from fire or explosion. In addition to the existing refinery systems, the project will have the following additional fire protection systems.

**Steam Turbine Lube Oil Areas Water Spray System**

This system will provide suppression for the steam turbine area lube oil piping and lube oil storage.

**Fire Hydrants/Hose Stations**

This system will supplement the plant’s fixed fire suppression systems. Water will be supplied from the plant fire water system.
Fire Extinguisher
The plant Control Room and other structures will be equipped with fire suppression systems as required by the local fire department and Chevron/Praxair plant protection policies and procedures.

Refinery Fire Protection Services
In the event of a major fire, the Refinery Emergency Response Team will respond and take all necessary actions to contain and extinguish the fire. The refinery’s Risk Management Plan (RMP) will include all information necessary to assess hazards and implement safe responses to fires, spills, and other emergencies.

After the PPRP components are installed at the Refinery, a revised RMP must be carried out to satisfy the CalARP Program. The RMP requires that a detailed hazards and operability study (HAZOP) of the changed components be carried out. The RMP also requires a revised offsite consequence analysis of plausible accidents. The new RMP must also include a revised accident prevention and training program as well as pre-startup safety reviews and safety requirements for contractors conducting hot work activities. The RMP must cover accidents that might happen from the Project that have been identified in the HAZOP. Section 8.5, Hazardous Materials Handling, contains additional information on the Risk Management Plan.

2.2.2.2 Personnel Safety Program
The PPRP will operate in compliance with federal and state occupational safety and health program requirements. Compliance with these programs will minimize project effects on employee safety.

2.3 Facility Reliability
This section discusses the expected facility availability, equipment redundancy, fuel availability, water availability, and project quality control measures.

2.3.1 Facility Availability
Because of the refinery steam and power needs, it is anticipated that the facility will normally be called upon to operate at high average annual capacity factors. The facility will be designed to operate between about 60 and 100 percent of base load in response to the refinery’s demands for electricity and steam.

The PPRP will be designed for an operating life of 30 years. Reliability and availability projections are based on this operating life. Operation and maintenance procedures will be consistent with industry standard practices to maintain the useful life status of plant components.

The percent of time that the cogen and STG is projected to be operated is defined as the “service factor.” The service factor considers the amount of time that a unit is operating and generating power and steam, whether at full or partial load. The projected service factor for the cogen and the STG, which considers projected percent of time of operation, differs from the equivalent availability factor (EAF), which considers the projected percent of energy production capacity achievable.
The EAF may be defined as a weighted average of the percent of full energy production capacity achievable. The projected equivalent availability factor for the PPRP is estimated to be approximately 98 to 99 percent.

The EAF differs from the “availability of a unit,” which is the percent of time that a unit is available for operation, whether at full load, partial load, or standby.

### 2.3.2 Redundancy of Critical Components

The following sections identify equipment redundancy as it applies to project availability. A summary of equipment redundancy is shown in Table 2.3-1. Final design could differ.

**TABLE 2.3-1**
Major Equipment Redundancy

<table>
<thead>
<tr>
<th>Description</th>
<th>Number</th>
<th>Note</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Cogen System</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CTGs and HRSGs</td>
<td>One new train added to two existing trains</td>
<td>Three cogen trains allow one train to be down for maintenance and the other two trains to provide adequate steam production to maintain full refinery throughput. Backup power during a cogen train outage is provided by the utility grid.</td>
</tr>
<tr>
<td>HRSG feedwater pumps</td>
<td>Two – 100 percent capacity</td>
<td>One operating and one spare full capacity pump for the new cogen train.</td>
</tr>
<tr>
<td>Condensate pumps</td>
<td>Two – 100 percent capacity</td>
<td>One operating and one spare full capacity pump for the new cogen train.</td>
</tr>
<tr>
<td>2,400-volt electrical switchgear busses, supply transformers and MCCs</td>
<td>Two – 100 percent capacity</td>
<td>Each bus and MCC are redundant to the other.</td>
</tr>
<tr>
<td>480-volt electrical switchgear busses, supply transformers and MCCs</td>
<td>Two – 100 percent capacity</td>
<td>Each bus and MCC are redundant to the other.</td>
</tr>
<tr>
<td><strong>Hydrogen Plant System</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>STG</td>
<td>One</td>
<td>STG power output is backed-up by other refinery generation and by power from the utility grid. Steam for the hydrogen plant process, normally supplied by extraction from the STG will be provided by letdown of high pressure steam through letdown stations.</td>
</tr>
<tr>
<td>STG condenser</td>
<td>One</td>
<td>Condenser must be in operation for steam turbine operation. The condenser will be provided with split water boxes to allow online tube cleaning and repair.</td>
</tr>
<tr>
<td>Circulating water pumps</td>
<td>Three – 50 percent capacity</td>
<td>Two operating and one standby pumps for the STG condenser.</td>
</tr>
<tr>
<td>STG Circulating water cooling tower</td>
<td>One</td>
<td>Cooling tower is multi-cell mechanical draft design.</td>
</tr>
</tbody>
</table>
2.3.2.1 Cogen Trains
Three separate CTG/HRSG power/steam cogeneration trains (one new and two existing) will operate in parallel within the cogen facility. Each CTG will provide approximately 30 percent of the total cogen facility power output. The exhaust gas from each CTG will be used to produce steam in the steam generation system. Thermal energy from the steam generation system will be distributed to the Refinery for use in refinery processes. The major components of the cogen facility consist of the following subsystems.

Combustion Turbine Generator Subsystems
The combustion turbine subsystems will include the combustion turbine, inlet air filtration and inlet evaporative cooling, generator and excitation systems, turbine lube oil system, hydraulic system, and turbine control and instrumentation. The combustion turbine will produce thermal energy through the combustion of natural gas (or LPG) and the conversion of the thermal energy into mechanical energy through rotation of the combustion turbine sections that drive the compressor sections and generator. Exhaust gas from the combustion turbine will be used to produce steam in the associated HRSG. The generator will be cooled by air circulation through the generator enclosure supplied via the CTG inlet filtration system. The generator excitation system will be a solid-state static system. Combustion turbine control and instrumentation (interfaced with the DCS) will cover the turbine governing system, and the protective system.

Steam Generation Subsystems
The steam generation subsystems will consist of the HRSG with duct burner and blowdown systems. The HRSG transfers heat from the CTG exhaust gas to feedwater for steam production. This heat transfer produces steam at the pressures and temperatures required by the steam turbine. The HRSG system consists of ductwork, heat transfer sections, an SCR system, an oxidation catalyst, and exhaust stack. The blowdown system provides vents and drains for each HRSG. The system includes safety and auto relief valves and processing of continuous and intermittent blowdown streams.

2.3.2.2 Boiler Feedwater System
The boiler feedwater system transfers feedwater from the deaerator to the HP and LP sections of the HRSG. The system will consist of two pumps, each pump sized for 100 percent capacity for supplying the HRSG at full steam production. The pump will be multistage, horizontal, motor-driven with intermediate bleed-off, and will include regulating control valves, minimum flow recirculation control, and other associated piping and valves.

2.3.2.3 Condensate System
The condensate system will provide a flow path from the condensate storage tank to the deaerator. The condensate system will include three 50-percent-capacity multistage, vertical, motor-driven condensate pumps.

2.3.2.4 Cogen Cycle Makeup and Storage
The cogen cycle makeup and storage subsystem will provide makeup water storage and pumping capabilities to supply boiler feed quality water for system cycle makeup and chemical cleaning operations. Major components of the system are one condensate water
storage tank (converted from an existing diesel fuel storage tank), providing a 5-hour supply of condensate water at peak load, and two 100-percent capacity, horizontal, centrifugal, cycle makeup water pumps.

2.3.2.5 **Hydrogen Plant Steam Turbine Generator**

The exhaust from the expanded steam from the STG will be condensed and recycled to the hydrogen plant heat recovery boiler feedwater system. Power from the STG will be used in the hydrogen plant to power the hydrogen production process. During some operating conditions, the STG will produce a small amount of excess power that would be supplied to the Refinery to supplement other refinery power generation.

**Steam Turbine Generator Subsystems**

The steam turbine will convert the thermal energy in the steam to mechanical energy to drive the STG. The basic subsystems will include the steam turbine and auxiliary systems, turbine lube oil system, and generator/exciter system. The generator will be water-cooled.

The hydrogen plant STG will be served by the following systems.

* **Circulating Water System**

The circulating water system will provide cooling water to the condenser for condensing steam turbine exhaust steam. In addition, the system will supply cooling water to the balance of the hydrogen plant for cooling heat load within the hydrogen production process. Approximately 50 percent of the cooling system capacity will be used for the STG and the balance will be used for hydrogen plant cooling loads. Major components for this subsystem will be a four-cell mechanical draft cooling tower, three 50-percent-capacity motor-driven vertical wet-pit circulating water pumps, and associated piping and valves.

* **Compressed Air**

The compressed air system will provide instrument air and service air to points of use throughout the facility. Compressed air for the cogen will be supplied from existing air headers in the cogen facility. Compressed air for the STG will be supplied from the hydrogen plant compressed air system.

2.3.3 **Fuel Availability**

Fuel will be delivered via existing natural gas, medium Btu gas pipelines currently serving the Refinery and by existing refinery fuel gas systems and piping. Since the PPRP will have two independent sources of natural gas, it is unlikely that the cogen would experience a loss of fuel.

2.3.4 **Water Availability**

The PPRP will use up to 532 afy of recycled water provided by the EBMUD for cooling tower markup. Cooling water will be cycled in the cooling tower five times. The blowdown will be discharged to the Refinery wastewater treatment system. Potable water will be used as an emergency supply to the cooling towers should the availability of recycled water be interrupted for more than 8 hours.

Potable water for drinking, safety showers, fire protection water, and service water, will be served from the existing refinery potable water service provided by EBMUD.
The availability of water to meet the needs of PPRP is discussed in more detail in Section 8.12, Water Resources.

### 2.3.5 Project Quality Control

The Quality Control Program that will be applied to the PPRP is summarized in this section. The objective of the Quality Control Program is to ensure that all systems and components have the appropriate quality measures applied; whether it is during design, procurement, fabrication, construction, or operation. The goal of the Quality Control Program is to achieve the desired levels of safety, reliability, availability, operability, constructability, and maintainability for the generation of electricity and steam.

The required quality assurance for a system is obtained by applying controls to various activities, according to the activity being performed. For example, the appropriate controls for design work are checking and review, and the appropriate controls for manufacturing and construction are inspection and testing. Appropriate controls will be applied to each of the various activities for the project.

#### 2.3.5.1 Project Stages

For quality assurance planning purposes, the project activities have been divided into the following nine stages that apply to specific periods of time during the project:

- **Conceptual Design Criteria.** Activities such as definition of requirements and engineering analyses.
- **Detail Design.** Activities such as the preparation of calculations, drawings, and lists needed to describe, illustrate, or define systems, structures, or components.
- **Procurement Specification Preparation.** Activities necessary to compile and document the contractual, technical, and quality provisions for procurement specifications for plant systems, components, or services.
- **Manufacturer’s Control and Surveillance.** Activities necessary to ensure that the manufacturers conform to the provisions of the procurement specifications.
- **Manufacturer Data Review.** Activities required to review manufacturers’ drawings, data, instructions, procedures, plans, and other documents to ensure coordination of plant systems and components, and conformance to procurement specifications.
- **Receipt Inspection.** Inspection and review of product at the time of delivery to the construction site.
- **Construction/Installation.** Inspection and review of storage, installation, cleaning, and initial testing of systems or components at the facility.
- **System/Component Testing.** Actual operation of generating facility components in a system in a controlled manner to ensure that the performance of systems and components conform to specified requirements.
- **Plant Operation.** As the project progresses, the design, procurement, fabrication, erection, and checkout of each generating facility system will progress through the nine stages defined above.
2.3.5.2 Quality Control Records

The following quality control records will be maintained for review and reference:

- Project instructions manual
- Design calculations
- Project design manual
- Quality assurance audit reports
- Conformance to construction records drawings
- Procurement specifications (contract issue and change orders)
- Purchase orders and change orders
- Project correspondence

For procured component purchase orders, Chevron has a list of qualified suppliers and subcontractors that has been developed over years. Before contracts are awarded, the subcontractors’ current capabilities will be evaluated. The evaluation will consider suppliers’ and subcontractors’ personnel, production capability, past performance, and quality assurance program.

During construction, field activities are accomplished during the last four stages of the project: receipt inspection, construction/installation, system/component testing, and plant operations. The construction contractor will be contractually responsible for performing the work in accordance with the quality requirements specified by contract.

The subcontractors’ quality compliance will be surveyed through inspections, audits, and administration of independent testing contracts.

Qualified and knowledgeable refinery plant operations and maintenance personnel will be assigned to the project and formal operational assurance reviews will be conducted to ensure operation and maintenance quality. A specific program for this project will be defined and implemented during initial plant startup.
FIGURE 2.1-2
PLOT PLAN EXISTING COGEN PLUS NEW COGEN 3000
CHEVRON POWER PLANT REPLACEMENT PROJECT
RICHMOND, CA
FIGURE 2.1-5
PLOT PLAN AND ELEVATIONS - H2 STG
CHEVRON POWER PLANT REPLACEMENT PROJECT
RICHMOND, CA
LEGEND

115 kV CB with
Disconnects
Med Voltage CB
115 kV to Med
Voltage transformer
115 kV Disconnect
Switch

FIGURE 2.1-7
REFINERY 115-kV DISTRIBUTION SYSTEM
CHEVRON POWER PLANT REPLACEMENT PROJECT
RICHMOND, CA

PG&E
EI SOBRANTE LINE 1
EI SOBRANTE LINE 2

COGEN #1
COGEN #2

BUS 1
BUS 2

Point of Common Coupling
(PCC)

CHEVRON STANDARD OIL SWITCHING STATION
(SOSS)

(115kV)

STG

12.47 kV SWITCHGEAR

13.8 kV

COGEN #1
COGEN #2

COGEN 2000
COGEN 3000
COGEN 1000

LEGEND

115 kV CB with
Disconnects
Med Voltage CB
115 kV to Med
Voltage transformer
115 kV Disconnect
Switch

NEW H2 PLANT
12.47 kV SWITCHGEAR

STG (New)

EXISTING

NEW

STG 800

COGEN 3000
(NEW)

13.8 kV

115-1
115-2
115-3
115-4
115-5
115-6
115-7
115-8
115-9
115-10
115-11
115-12
115-13
115-14
115-15
115-16
115-17
115-18

13.8 kV

682 681 683
782 781 783
882 881 883
982 981 983
FIGURE 2.1-8
115-kV TOWERS
CHEVRON POWER PLANT REPLACEMENT PROJECT
RICHMOND, CA
FIGURE 2.1-14
SIMPLIFIED FLOW DIAGRAM
CHEVRON POWER PLANT REPLACEMENT PROJECT
RICHMOND, CA
### Case 1: 1% Hot Day Case (Design Basis)

<table>
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<tr>
<th>Steam Number</th>
<th>1</th>
<th>1A</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
<th>20</th>
<th>21</th>
<th>30</th>
<th>31</th>
<th>32</th>
</tr>
</thead>
<tbody>
<tr>
<td>Description</td>
<td>Turbine Inlet</td>
<td>Turbine Inlet</td>
<td>less Gland</td>
<td>Losses</td>
<td>Extraction</td>
<td>Flow</td>
<td>Plant 2 Process + Utility Steam</td>
<td>Plant 1 Process + Utility Steam</td>
<td>Condensate Flow</td>
<td>CW To Condenser</td>
<td>CW From Condenser</td>
<td>CWS from Tower</td>
</tr>
<tr>
<td>Temperature (F)</td>
<td>704.0</td>
<td>704.0</td>
<td>704.0</td>
<td>582.0</td>
<td>582.0</td>
<td>582.0</td>
<td>126.1</td>
<td>80.0</td>
<td>97.2</td>
<td>79.9</td>
<td>97.2</td>
<td>70.0</td>
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<tr>
<td>Pressure (psig)</td>
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<td>960.0</td>
<td>960.0</td>
<td>535.0</td>
<td>535.0</td>
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<td>55.3</td>
<td>0.0</td>
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<tr>
<td>Mass Flow (lb/hr)</td>
<td>363,784</td>
<td>360,146</td>
<td>3,638</td>
<td>210,120</td>
<td>105,060</td>
<td>105,060</td>
<td>150,026</td>
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<td>150,026</td>
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</tr>
<tr>
<td>Molecular Weight</td>
<td>18.02</td>
<td>18.02</td>
<td>18.02</td>
<td>18.02</td>
<td>18.02</td>
<td>18.02</td>
<td>18.02</td>
<td>18.02</td>
<td>18.02</td>
<td>18.02</td>
<td>18.02</td>
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</tr>
</tbody>
</table>

### Case 2: Average Day Case

<table>
<thead>
<tr>
<th>Steam Number</th>
<th>1</th>
<th>1A</th>
<th>2</th>
<th>3</th>
<th>4</th>
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<th>6</th>
<th>20</th>
<th>21</th>
<th>30</th>
<th>31</th>
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<tbody>
<tr>
<td>Description</td>
<td>Turbine Inlet</td>
<td>Turbine Inlet</td>
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<td>Losses</td>
<td>Extraction</td>
<td>Flow</td>
<td>Plant 2 Process + Utility Steam</td>
<td>Plant 1 Process + Utility Steam</td>
<td>Condensate Flow</td>
<td>CW To Condenser</td>
<td>CW From Condenser</td>
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<td>Temperature (F)</td>
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<tr>
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<td>105,060</td>
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### Case 3: 1% Cold Day Case

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**FIGURE 2.1-15**

H2 STG AND H&M BALANCE
CHEVRON POWER PLANT REPLACEMENT PROJECT
RICHMOND, CA
FIGURE 2.1-17
COGEN 3000 WATER BALANCE
(MAXIMUM AMBIENT - 85°F)
CHEVRON POWER PLANT REPLACEMENT PROJECT
RICHMOND, CA
This is representative of the cooling water demand for only the STG, NOT the whole plant.
FIGURE 2.1-19
COGEN 3000 AND STG LAYDOWN
AND LINEARS
CHEVRON POWER PLANT REPLACEMENT PROJECT
RICHMOND, CA

LEGEND

- COGEN 3000 Plot Space
- H2 Plant STG, Switchgear, and Colling Tower Plot Space
- Refinery Laydown Areas (will be used partially for COGEN and H2 Plant as well as other projects and maintenance activities)
- COGEN 3000 115 Kv Transmission Lines to be reconducted
- H2 STG 12.47 Kv Lines to be tied-in to existing refinery transmission lines

SCALE IS APPROXIMATE

0 300 600 Feet

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