Application for Certification for

East Altamont Energy Center

Submitted to:

California Energy Commission
Sacramento, California

Volume 1

March 2001

by

East Altamont Energy Center, LLC

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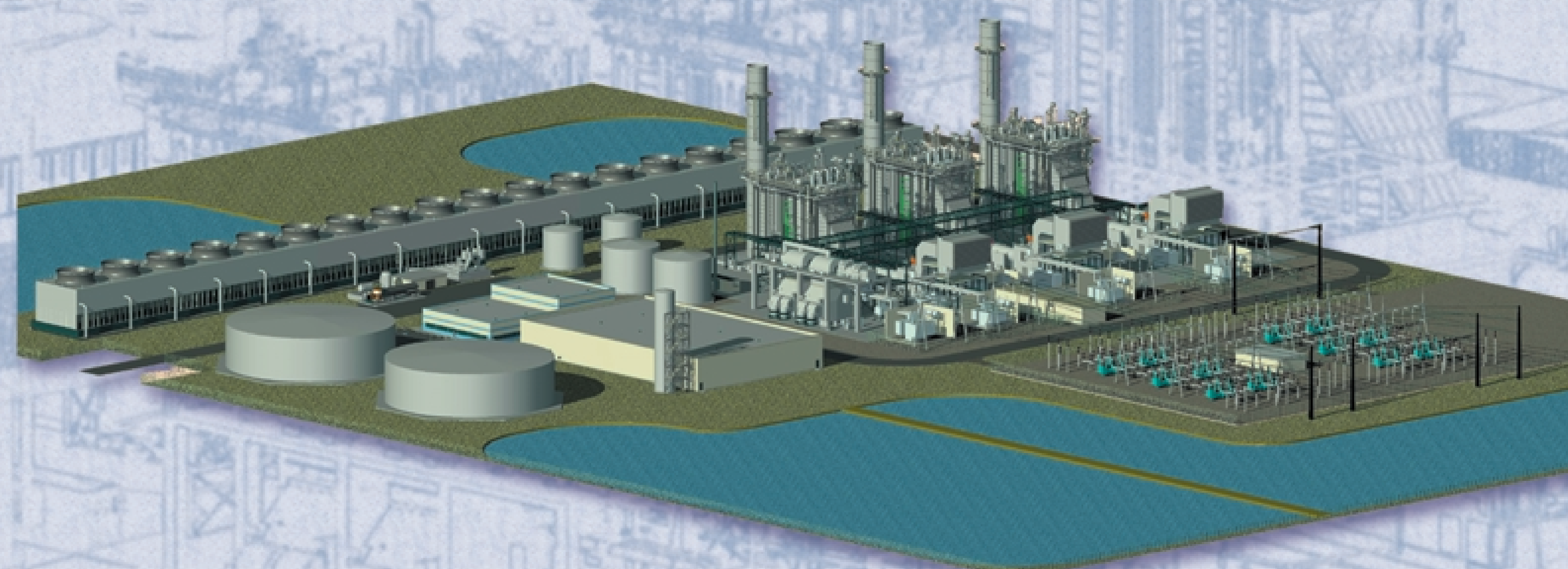

by

East Altamont Energy Center, LLC

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1.0 Executive Summary

1.1 Project Overview

This Executive Summary comprises the following sections. Section 1.1 is a project overview of the proposed East Altamont Energy Center (EAEC). Section 1.2 provides a general project schedule, and Section 1.3 provides project ownership details. The project alternatives are discussed in Section 1.4. The environmental considerations are discussed in Section 1.5. Key benefits of the project are discussed in Section 1.6, and the list of persons who prepared the Application for Certification (AFC) is referenced in Section 1.7.

Calpine Corporation (Calpine) proposes to develop a natural-gas-fired generating Facility at the northeastern edge of Alameda County (see Figure 1.1-1). The proposed EAEC will be a high-efficiency, combined-cycle Facility that will sell electricity in the electricity market established in California on March 31, 1998.

EAEC will be a "merchant plant," which is a Facility that is not owned by a utility or utility affiliate yet produces and sells energy into the electric utility system. A merchant plant is not supported by any power purchase agreement with a utility. Instead, a merchant plant, such as EAEC, will sell its output on short- and mid-term contracts directly to customers or into the spot power market, such as the California Power Exchange. As a result, the project will provide California electric customers with a highly competitive source of clean energy, with all project economic risks being borne by the owners.

EAEC will consist of the following features, shown on Figure 1.1-2:

- A 1,100-megawatt (MW) nominal, natural-gas-fired, combined-cycle generating Facility consisting of three modern combustion turbines and a condensing steam turbine.
- A 230-kilovolt-(kV) switchyard.
- Approximately 0.5 mile of new 230-kV transmission line onsite to join an existing 230-kV transmission line that connects to the Western Area Power Administration (Western) Substation.
- Approximately 1.4 miles of new natural gas supply line.
- Approximately 4.6 miles of to-be-constructed recycled water supply line.
- Approximately 2.1 miles of new water supply line.
- Approximately 16 acres of stormwater retention, waste storage, and evaporation ponds.
- A groundwater well and small treatment system for domestic water uses.
- A septic tank/leach system for sanitary wastes.

Calpine currently has a purchase option on a 174-acre parcel of agricultural land. The parcel is located in Township 1 South, Range 4 East, Mount Diablo base and meridian (MDB&M).

The plant site would occupy up to 55 acres near the center of the property, with the remainder available for lease as agricultural land. The legal description of the 174-acre parcel is included in Appendix 1A. Figure 1.1-2 shows the proposed routes for linear facilities.

Calpine's approach to identifying potential project sites is based on the desirability of potential sites that have low potential for environmental impacts, while allowing for access to electrical markets that serve areas with high and/or increasing electrical demand. The proposed project site is consistent with this philosophy because the site is located in a rural, sparsely populated portion of Alameda County adjacent to Western's Tracy substation, allowing service to customers of the Modesto Irrigation District (MID), Turlock Irrigation District (TID), Western, and through Pacific Gas & Electric Company (PG&E), the California Independent System Operator (ISO). This project site is also strategically located near critical infrastructure, reducing the need for long linear facilities (water and natural gas pipelines and electrical transmission lines) and further minimizing the environmental impacts associated with construction and operation of the linear facilities.

Tracy is the city nearest to the site, approximately 8 miles to the southeast. Other major landmarks are Clifton Court Forebay, approximately 2 miles to the north; Bethany Reservoir, approximately 5 miles to the southwest; Livermore, approximately 12 miles to the west; and the town of Byron, 5 miles to the north. The newly approved town of Mountain House will be 1 mile southeast of the project at its nearest point. The project site is located in Alameda County, but gas- and waterlines would cross portions of Contra Costa and San Joaquin counties in addition to Alameda County. The site is zoned for agricultural uses, but Alameda County has advised the Applicant that this use is permittable under the Alameda County Zoning Code and the East County Area Plan (ECAP). Rezoning is not required to permit the project.

Western's Tracy substation is located approximately 0.25 mile west of and across Mountain House Road from the site. Electrical transmission lines would run south from the site approximately 0.5 mile to join existing 230-kV lines that connect with Western's Tracy substation. The project would use gas from PG&E's transmission backbone pipeline located approximately 1.5 miles west of the project site (Figure 1.1-2). A 20-inch pipeline would be constructed from the PG&E pipeline tap point to the project site. Development of a generating Facility in the area is consistent with the existing utility infrastructure.

Cooling and process water for the Facility would be conveyed by 24-inch pipe along an existing dirt road from Canal 45, operated by Byron Bethany Irrigation District (BBID). The project is in BBID's district, and BBID has adequate supplies to serve the project, as indicated in its letter of February 6, 2001 (Appendix 8.14A). BBID has evaluated the feasibility of providing its customers with recycled wastewater from the Mountain House Community Service District Wastewater Treatment Plant (MHCSD WWTP). MHCSD is within the District, is contracted to buy water from BBID, and welcomes this plan. As recycled wastewater becomes available from the MHCSD WWTP, BBID would supply the project with the maximum available recycled water to the extent feasible for cooling water, supplementing with its usual source. The project will incorporate onsite storage.

Parcel numbers and the names of the owners of land within 1,000 feet of the site and within 500 feet of electric transmission line, waterlines, and natural gasline corridors are included in Appendix 1B. The landowners that the natural gasline, electric transmission line, and waterlines will cross (or encroach upon) and assessor parcel maps showing the approximate location of these utility lines are included in Appendix 1B. Figure 1.1-3 shows the jurisdiction of property under Calpine interest.

The generating Facility will consist of three combustion turbine generators (CTGs) with heat recovery steam generators (HRSGs) and one steam turbine generator (STG), with a nominal total generating capacity of 1,100 MW. The turbines are expected to be General Electric PG 7251 (FB) units. One nominal 100,000-pound-per-hour auxiliary boiler will also be included to provide steam as needed for auxiliary purposes. A 19-cell mechanical-draft evaporative cooling tower will also be installed to provide cooling water for the steam turbine condenser. Additional auxiliary equipment will include a natural-gas-fired 1,000-kW emergency generator and a 370-horsepower (hp) diesel fire pump.

1.2 Project Schedule

Construction is planned to begin in June 2002 and be completed by June 2004. Plant testing will commence in the first quarter 2004, and full-scale commercial operation is expected to commence in June 2004.

1.3 Project Ownership

Calpine is the sponsor of the EAEC, which will be owned by the East Altamont Energy Center Limited Liability Company (EAEC LLC), a wholly owned subsidiary of Calpine Corporation.

1.3.1 Summary of Calpine

Calpine is an independent power developer, owner, and operator. It is headquartered in San Jose, California. As of March 2001, Calpine owns an interest in 50 power generation facilities and geothermal steamfields having an aggregate capacity in excess of 5,874 MW. In California, Calpine has an interest in more than eight cogeneration facilities, including the Gilroy, King City, and Greenleaf 1 and 2 plants. Calpine recently received certification from the California Energy Commission (CEC) to construct its proposed Sutter Generating Facility near Yuba City, and the Los Medanos and Delta Energy Centers in Pittsburg, California. Calpine also owns geothermal facilities at the Geysers. Calpine is a publicly traded company with the NYSE stock symbol CPN.

1.3.2 Other Agreements

The EAEC LLC will have an Interconnection Agreement with Western that will allow EAEC power to reach the marketplace. EAEC LLC will also contract with PG&E for natural gas transmission to EAEC and with various suppliers for fuel. EAEC LLC will contract with BBID for water supply, and BBID in turn plans to contract with MHCSD to convey recycled wastewater when it becomes available from MHCSD WWTP.

The legal relationship between EAEC LLC, the owner of EAEC, Western, PG&E, and other suppliers will be contractual only (one of supplier/user or seller/buyer of services or products).

1.4 Project Alternatives

A "No Project" Alternative was considered and rejected as inconsistent with California's program to develop merchant power generation facilities, the objective of which is to increase reliability and stabilize prices by increasing electric supplies. In addition, the "No Project" Alternative could result in greater fuel consumption and air pollution in the state because generation from older, less efficient plants with higher air emissions would not be reduced by generation from cleaner, more efficient plants, such as EAEC. Other possible alternative sites in the general vicinity of the proposed site were reviewed and found to be less acceptable than the site described in Section 1.1. Alternative routes for the natural gas line, electric transmission line, and waterlines were also reviewed and found to be less acceptable than the chosen routes.

Several alternative generating technologies were reviewed in a process that led to the selection of a modern, yet proven, combustion turbine combined-cycle arrangement for EAEC using natural gas for fuel. The alternative technologies included conventional oil and natural-gas-fired plants, simple-cycle combustion turbines, biomass-fired plants, waste-to-energy plants, solar plants, wind generation plants, and others. None of these technologies was considered equal to or better than the combined-cycle technology selected for EAEC. A complete discussion of project alternatives is presented in Section 9.0 of this AFC. Electric transmission connection alternatives, natural gas pipeline alternatives, and waterline alternatives are presented in Sections 5.0, 6.0, and 7.0, respectively.

A schematic arrangement of the plant is presented on Figure 1.1-4. Full-page photographs of the site and transmission lines prior to and after construction are shown on Figures 1.1-5 and 1.1-6, respectively.

1.5 Environmental Considerations

Sixteen areas of possible environmental impact from the proposed project were investigated. Detailed descriptions and analyses of these areas are presented in Sections 8.1 through 8.16 of the AFC. Without the implementation of mitigation measures, several of these areas could have environmental effects. The possible effects of key areas are described briefly in this section.

1.5.1 Air Quality

The site is located in the Bay Area Air Quality Management District (BAAQMD), a State of California ambient air quality standards attainment area for both ozone and particulate matter with a diameter less than 10 microns (PM_{10}). An assessment of the impact to air quality was performed using detailed air dispersion modeling. The air impacts from the project will be mitigated by the advanced nature of the combustion turbine emission control technology. Also, emission reduction credits (ERCs) will be obtained to offset volatile organic compounds (VOCs), oxides of nitrogen (NO_x) (both precursors of ozone), and PM_{10}. These mitigation measures will result in the project having no significant adverse impact on air quality. See Section 8.1 for a detailed analysis of air quality.

1.5.2 Water Resources

The project is located within the BBID, and BBID would provide cooling and process water to the EAEC. Initially, BBID would supply raw water from its existing surface water supply at Canal 45. BBID is currently developing a recycled water feasibility study for its service area. As recycled wastewater becomes available from the MHCSD WWTP, BBID would supply recycled water to replace as much BBID raw water as feasible and supplement with its supply from Canal 45. Recycled wastewater would be treated to meet at least Title 22 requirements. The quantity of water required is about 4,600 –acre-feet per year (AFY), of which approximately 3,000 acre-feet is projected to come from recycled water by Year 2024. Wastewater would be discharged to onsite treatment and evaporation ponds. The demineralizers would be regenerated offsite. There would be no wastewater discharges from the site. Stormwater runoff would be controlled in a manner to prevent offsite erosion and water quality degradation consistent with requirements of the Regional Water Quality Control Board (RWQCB) and Alameda County pursuant to a stormwater National Pollutant Discharge Elimination System (NPDES) permit and county erosion and sediment control plan. Section 7.0 provides a detailed description of water supply, and Section 8.14 provides a detailed description of water resources.

1.5.3 Visual

The project site lies in the San Joaquin Valley landscape zone, and is on the edge of the Sacramento-San Joaquin Delta. The surrounding landscape is devoted to agriculture and has an open appearance; it also includes an unusually high concentration of major infrastructure facilities, creating a scene that is a mix of the rural and technological. The site itself is flat and open, and it contains no features that would be considered to be scenic resources. In most of the views toward the site that were evaluated, the visual quality of the landscapes included in the views was found to be moderately low to moderate. Residences in the project viewshed are relatively low in number, and the closest lie more than 0.5 mile from the site.

The generating Facility's major features would include two HRSGs that are 150 feet long, 60 feet wide, 75 feet high to the top of the casing, and 108 feet high to the top of the highest relief valves and vent silencers. The HRSG stacks would be 175 feet tall. The cooling tower structure would be 1,030 feet long, 56 feet wide, 43 feet high to the top of the deck and 57 feet high to the top of the cell stacks. The Facility would have an orderly appearance, would be painted using a neutral color scheme designed to break up its mass and relate it to its backdrop, and would be surrounded by landscaping intended to provide screening and integration of the Facility into its landscape setting.

None of the views toward the site were found to have the combination of conditions (moderate to high level of visual quality and moderately high to high level of visual sensitivity) that CEC staff criteria indicate are required to create the pre-conditions for a significant visual impact to occur. In addition, the project is in general conformance with all laws, ordinances, regulations, and standards (LORS) related to visual resources in Alameda County plans and zoning ordinance provisions that pertain to this area. The lighting associated with the project would be limited, and would not pose a hazard or adversely affect day or nighttime views toward the site.

1.5.4 Biology

Sensitive biological resources in the EAEC project area include the potential occurrence of California red-legged frog, San Joaquin kit fox, and Swainson's hawk. With appropriate mitigation the project would cause no significant adverse impact to these species. Calpine has consulted with the U.S. Fish and Wildlife Service (USFWS), California Department of Fish and Game (CDFG), U.S. Army Corps of Engineers (ACOE) and National Marine Fisheries Service (NMFS) and will obtain a permit for incidental take, pursuant to Section 7 prior to construction, if required to do so. Impacts to sensitive biological resources from the construction and operation of EAEC and the project linears will not be significant. Section 8.2 provides a detailed analysis of biological resources and the methods proposed to avoid significant impacts to them.

1.5.5 Noise

Ambient noise measurements were taken to determine the L_{90} (the noise level that is exceeded during 90 percent of the measurement period) nighttime noise level at the nearest residence (i.e., sensitive receptor). Noise modeling was used to determine the contribution to the nighttime ambient levels the plant would make during operations. Nighttime noise levels at the nearest residences will be approximately 45 decibels A-rated (dBA), which is within county/local requirements. Since the noise level at the nearest receptor will be in accordance with county/local LORS, no adverse impact is expected from to the normal operation of the Facility.

1.6 Key Benefits

1.6.1 Environmental

EAEC will employ advanced, high-efficiency combustion turbine technology and Selective Catalytic Reduction (SCR) to minimize emissions from the Facility. NO_x emissions, a precursor to smog produced by EAEC, will be approximately 90 percent less than those for existing older generating facilities. In addition to the significant reduction of emissions, EAEC's operating efficiency will be such that the plant will consume 40 percent less fuel than existing older plants of similar size. EAEC will also obtain emission offsets to more than compensate for the emissions. Hence, the EAEC project will provide a net air quality improvement for the region.

EAEC will also minimize freshwater use. Treated effluent (i.e., recycled water) from the MHCSD WWTP will be used for plant cooling and process water needs when available. This will allow for the commercial use of a wastewater stream that might otherwise be discharged into the Delta without providing any useful or beneficial application.

1.6.2 Employment

The project will provide for a peak of approximately 400 construction jobs over a 2-year period and up to 40 skilled, family-wage positions throughout the life of the plant.

1.6.3 Tax Base

EAEC will be a significant tax contributor, supporting the services and programs of Alameda County. The California State Board of Equalization has determined that a power generation Facility should be assessed at the county level, resulting in an allocation to the local tax jurisdiction where the Facility is located.

1.6.4 Energy Efficiency

EAEC will be an efficient, environmentally responsible source of economic and reliable energy to serve the growing energy demands of the deregulated California Energy Market. EAEC will help ensure reliable, clean, low-cost electricity in the future.

1.7 Persons Who Prepared the AFC

Persons with primary responsibility for the preparation of each section of this AFC are listed in Appendix 1C.

LEGEND

PROJECT SITE

N

2 0 2 Miles

1:250,000

SCALE IS APPROXIMATE

FIGURE 1.1-1
GENERAL VICINITY MAP

APPLICATION FOR CERTIFICATION
FOR EAST ALTAMONT ENERGY CENTER

CH2MHILL

CH2M Hill RDD ArcView Project File \\Thor\Cart1\rddgis\east_alt\east_alt.apr fig1_1_1.pdf 5:29 p.m. 03-13-2001

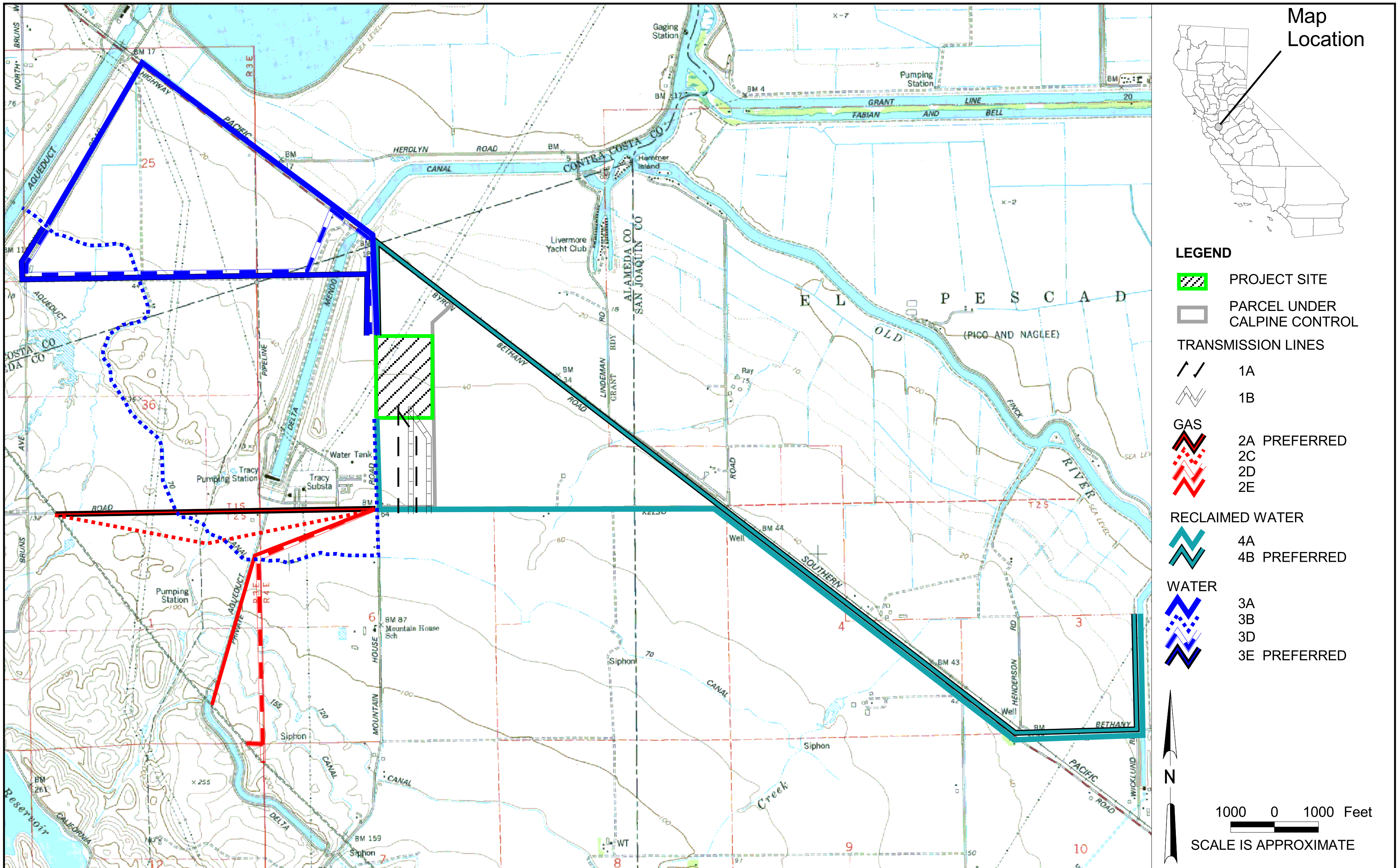
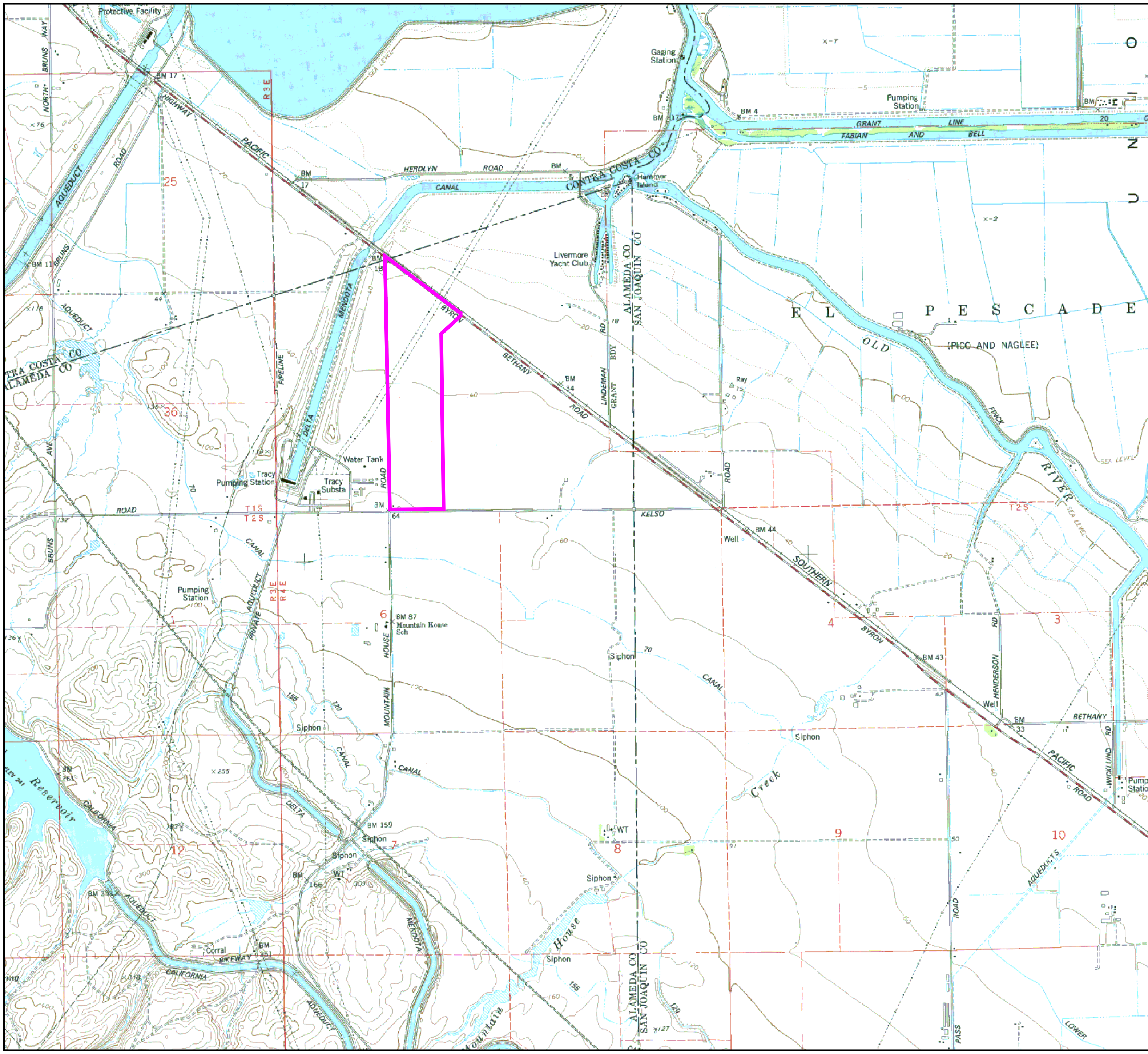


FIGURE 1.1-2
EAEC SITE AND LINEAR FACILITIES LOCATION MAP

APPLICATION FOR CERTIFICATION FOR EAST ALTAMONT ENERGY CENTER

CH2MHILL

CH2M Hill RDD ArcView Project File \\Thor\Cart1\rddgis\east_alt\east_alt.apr fig_1_1_2.pdf 5:20 p.m. 03-13-2001



LEGEND

PARCEL UNDER CALPINE CONTROL

N

1000 0 1000 Feet

SCALE IS APPROXIMATE

FIGURE 1.1-3
JURISDICTION OF PROPERTY UNDER CALPINE INTEREST

APPLICATION FOR CERTIFICATION FOR EAST ALTAMONT ENERGY CENTER

CH2MHILL

LEGEND

ACCESS ROAD

LAYDOWN AREA

N

200 0 200 Feet

SCALE IS APPROXIMATE

FIGURE 1.1-4
1,100 MW COMBINED CYCLE PLANT SITE PLAN

APPLICATION FOR CERTIFICATION
FOR EAST ALTAMONT ENERGY CENTER

CH2MHILL

CH2M Hill RDD ArcView Project File \\Thor\Cart1\rddgis\east_alt\east_alt.apr fig_1_1_4.pdf 5:32 p.m. 03-13-2001

FIGURE 1.1-5
APPEARANCE OF SITE BEFORE CONSTRUCTION
APPLICATION FOR CERTIFICATION FOR EAST ALTAMONT ENERGY CENTER

3271_02 (3/26/01)

CH2MHILL

FIGURE 1.1-6
APPEARANCE OF SITE AFTER CONSTRUCTION
APPLICATION FOR CERTIFICATION FOR EAST ALTAMONT ENERGY CENTER

3271_02 (3/26/01)

CH2MHILL

2.0 Project Description

2.1 Introduction

The following sections describe the design and operation of the proposed project, associated electric transmission lines, natural gas supply line, and water lines. Site selection and alternative sites considered are presented in Section 9.0.

Section 2.1 is the introduction, which provides a brief overview of the project. Section 2.2 contains a description of the generating facility, its design, and its proposed operation. Section 2.3 discusses the safety design of the facility. Section 2.4 discusses the expected facility reliability. Section 2.5 refers the LORS applicable to each engineering discipline to Appendices 10A through 10G.

The East Altamont Energy Center (EAEC) will be a nominal 1,100-megawatt (MW) natural-gas-fired combined-cycle generating facility, with a 230-kilovolt (kV) switchyard and approximately 0.5 mile of new 230-kV transmission lines. The switchyard, which will be owned by Western Area Power Authority (Western), will function as an extension of Western's existing Tracy substation, located across Mountain House Road, immediately to the west of the project site. Natural gas for the facility will be delivered via approximately 1.4 miles of new 20-inch pipeline that will connect to Pacific Gas and Electric's (PG&E) existing gas transmission line southeast of the Bethany gas compressor station located to the west of the site near the intersection of Bruns Road and Kelso Road. Roughly 4,600 acre-feet per year (AFY) of raw water for cooling tower and process makeup water will be supplied by Byron Bethany Irrigation District (BBID) via a 2.1-mile pipeline.

Cooling water will be cycled three to eight times (depending on water quality) in the cooling tower; wastewater will then be concentrated and disposed of onsite using a zero-liquid discharge system and evaporation ponds. Domestic water will be provided by a new onsite well.

The EAEC will be located on approximately 55 acres within a 174-acre parcel of land under the Applicant's control. The site is located in unincorporated Alameda County, approximately 1 mile west of the San Joaquin County line, and 1 mile south and east of the Contra Costa County line. Figure 2.1-1 (all figures located at the back of this section) shows the location of the generating facility, electric transmission line, natural gas supply line, raw water supply line, and recycled waterline. Additional information on ownership and location are included in Section 1.0.

2.2 Generating Facility Description, Design, and Operation

This section describes the facility's conceptual design and proposed operation.

2.2.1 Site Arrangement and Layout

The site plan on Figure 2.2-1 and typical elevation views on Figure 2.2-2 illustrate the location and size of the proposed generating facility.

The site is located between Byron Bethany Road and Kelso Road, with Mountain House Road forming the western border of the site. Access to the site will be provided via a 30-foot-wide road leading from Mountain House Road to the site and terminating at a controlled gate. Most of the site will be paved to provide internal access to all project facilities and onsite buildings. The switchyard and areas around equipment, where not paved, will have gravel surfacing. Site access roads are shown on Figure 2.2-3.

Up to approximately 55 fenced acres will be required to accommodate the generation facilities, including the storage tank areas, parking area, control/administration building, water treatment facility, evaporation ponds, wastewater recycle pond, stormwater retention pond, switchyard, emission control equipment, and generation equipment.

2.2.2 Process Description

The generating facility will consist of three combustion turbine generators (CTGs) equipped with dry, low oxides of nitrogen (NO_x) combustors and steam injection power augmentation capability; three heat recovery steam generators (HRSG) with duct burners; one condensing steam turbine generator (STG); a deaerating surface condenser; a mechanical-draft cooling tower; and associated support equipment providing a nominal total generating capacity of 1,100 MW. The combustion turbines are expected to be General Electric PG 7251 (FB) units. One nominal 100,000-pound-per-hour auxiliary boiler will also be included in order to provide steam as needed for auxiliary purposes. A 19-cell mechanical-draft evaporative cooling tower will also be installed to provide cooling water for the steam turbine surface condenser and other cooling loads. Additional auxiliary equipment will include a 1,000-kW natural-gas-fired emergency generator and a 370-horsepower (hp) diesel fire pump.

Each CTG will generate approximately 180 MW at base load under average ambient conditions. The CTG exhaust gases will be used to generate steam in the HRSGs. The HRSGs will use reheat design with duct firing. Steam from the HRSGs will be admitted to a condensing steam turbine generator. Approximately 550 MW will be produced by the steam turbine when the CTGs are operating at base load at average ambient conditions with maximum duct firing within the HRSGs. The project is expected to have an overall annual availability in the general range of 92 to 98 percent.

The generating facility base load operation heat balance is shown on Figures 2.2-4a and 2.2-4b. This balance is based on an ambient dry bulb temperature of 61°F (annual average) with no fogging of the combustion air, no steam injection for power augmentation, and no duct firing.

Associated equipment will include emission control systems necessary to meet the proposed emission limits. NO_x emissions will be controlled to 2.0 parts per million by volume, dry basis (ppmvd) corrected to 15 percent oxygen on an annual average basis (2.5 ppmvd on a short-term basis) by a combination of low NO_x combustors in the CTGs and selective catalytic reduction (SCR) systems in the HRSGs. A carbon monoxide (CO) catalyst will be installed in the HRSGs to limit CO emissions from the CTGs to 6 ppmvd at 15 percent oxygen. The auxiliary boiler will be limited to 9 ppmvd NO_x at 3 percent oxygen and 50 ppmvd CO at 3 percent oxygen.

2.2.3 Generating Facility Cycle

CTG combustion air flows through the inlet air filter and fogging section and associated air inlet ductwork, is compressed in the gas turbine compressor section, and then flows to the CTG combustor. Natural gas fuel is injected into the compressed air in the combustor and ignited. The hot combustion gases expand through the power turbine sections of the CTGs, causing them to rotate and drive the electric generators and CTG compressors. The hot combustion gases exit the turbine sections at approximately 1,150°F and enter the HRSGs. In the HRSGs, boiler feedwater is converted to superheated steam and delivered to the steam turbine at three pressures: high-pressure (HP), intermediate-pressure (IP), and low-pressure (LP). The use of multiple steam delivery pressures increases cycle efficiency and flexibility. High-pressure steam expands through the HP section of the steam turbine. This expanded steam, referred to as cold reheat steam, is combined with the IP steam and returned to the reheater section of the HRSGs. This mixed, reheated steam (called "hot reheat") is then expanded in the IP steam turbine section. Steam exiting the IP section of the steam turbine is mixed with LP steam and expanded in the LP steam turbine section. Steam leaving the LP section of the steam turbine 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 a mechanical-draft cooling tower.

2.2.4 Combustion Turbine Generators, Heat Recovery Steam Generators, Steam Turbine Generator and Condenser, and Auxiliary Boiler

Electricity is produced by the three CTGs and the STG. The system also contains an auxiliary boiler. The following paragraphs describe the major components of the generating facility.

2.2.4.1 Combustion Turbine Generators

Thermal energy is produced in the CTGs through the combustion of natural gas, which is converted into mechanical energy required to drive the combustion turbine compressors and electric generators. Three "F" class CTGs have been selected for the EAEC; these CTGs will be supplied by General Electric.

Each CTG system consists of a stationary combustion turbine generator, supporting systems, and associated auxiliary equipment. The CTGs will have power augmentation capability by use of steam injection upstream of the power turbine section.

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

- Inlet air foggers
- Inlet air filters
- Metal acoustical enclosure
- Double lube oil cooler
- Dry low NO_x combustion system
- Compressor wash system

- Fire detection and protection system
- Fuel heating system

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

2.2.4.2 Heat Recovery Steam Generators

The HRSGs provide for the transfer of heat from the exhaust gases of the CTGs to the feedwater, which is turned into steam. The HRSGs will be three-pressure, natural circulation units equipped with inlet and outlet ductwork, duct burners, insulation, lagging, and separate exhaust stacks.

Major components of each HRSG include an LP economizer, LP drum, LP evaporator, LP superheater, IP economizer, IP evaporator, IP drum, IP superheaters/reheaters, HP economizers, HP evaporator, HP drum, and HP superheaters. The LP economizer receives condensate from the condenser hot well via the condensate pumps. The LP economizer is the final heat transfer section to receive heat from the combustion gases prior to their exhausting to the atmosphere.

From the LP economizer, the condensate is directed to the LP drum where it is available to generate LP steam and supply condensate to the boiler feed pumps. The boiler feed pumps draw suction from the LP drum and provide additional pressure to serve the separate IP and HP sections of the HRSG.

Feedwater from the boiler feed pumps is sent to the HP section of the HRSG. High-pressure feedwater flows through the HP economizer where it is preheated prior to entering the HP steam drum. Within the HP steam drum, a saturated liquid state will be maintained. The saturated water will flow through downcomers from the HP steam drum to the inlet headers at the bottom of the HP evaporator. Saturated steam will form in the tubes as energy from the combustion turbine exhaust gas is absorbed. The HP-saturated liquid/vapor mixture will then return to the steam drum where the two phases will be separated by the steam separators in the drum. The saturated water will return to the HP evaporator, while the vapor continues on to the HP superheater. Within the HP superheater, the temperature of the HP steam will be increased above its saturation temperature, or "superheated" prior to being admitted to the HP section of the steam turbine.

Feedwater will also be sent to the IP section of the HRSG by an interstage bleed from the boiler feed pumps. Similar to the HP section, feedwater will be preheated in the IP economizer and steam will be generated in the IP evaporator. The saturated IP steam will pass through an IP superheater and then be mixed with "cold reheat" steam from the discharge of the steam turbine HP section. The blended steam will then pass through two additional IP superheaters reheating the steam to a superheated state. The "hot reheat" steam will then be admitted to the steam turbine IP section.

Condensate will be preheated by the LP economizer prior to entering the LP steam drum. Similar to the HP and IP sections, steam will be generated in the LP evaporator and superheated in the LP superheater. The superheated LP steam will then be admitted to the LP section of the steam turbine along with the steam exhausting from the steam turbine IP section.

Duct burners will be installed in the HRSGs. These burners will provide the capability to increase steam generation and provide greater operating flexibility and improved steam temperature control. The duct burners will burn natural gas. The duct burner for each HRSG will be sized for a heat output of up to 660 million British thermal units (Btus) per hour on a lower heating value (LHV) basis.

The HRSG will be equipped with an SCR emission control system that will use ammonia vapor in the presence of a catalyst to reduce NO_x in the exhaust gases. The catalyst module will be located within the HRSG casing. Diluted ammonia vapor (NH_3) will be injected into the exhaust gas stream via a grid of nozzles located upstream of the catalyst module. The subsequent chemical reaction will reduce NO_x to nitrogen and water, resulting in an NO_x concentration in the HRSG exhaust gas no greater than 2.0 ppmvd at 15 percent oxygen (on an average annual basis).

An oxidation catalytic converter will also be installed within the HRSG casing to control the concentration of CO in the exhaust gas emitted to atmosphere to no greater than 6 ppmvd at 15 percent oxygen. Exhaust from each HRSG will be discharged from individual 175-foot-tall exhaust stacks.

2.2.4.3 Steam Turbine Generator

The steam turbine system consists of a condensing steam turbine generator (STG) with reheat, gland steam system, lubricating oil system, hydraulic control system, and steam admission/induction valving.

Steam from the HRSG HP, IP, and LP superheaters enters the associated steam turbine sections through the inlet steam system. The steam expands through multiple stages of the turbine, driving the generator. On exiting the turbine, the steam is directed into the surface condenser.

2.2.4.4 Auxiliary Boiler

An auxiliary boiler, capable of providing up to 100,000 pounds per hour (lb/hr) of saturated steam at 400 pounds per square inch gauge (psig), will be provided for HRSG HP steam drum sparging, condenser hotwell sparging, steam turbine gland steam, and deaeration steam when the plant is offline. For prolonged outages, a nitrogen blanket will be used to lay-up the HRSG to alleviate the need to run the auxiliary boiler (decrease in fuel use and emissions). An electric superheater will be provided for the steam turbine gland steam. The auxiliary boiler will be a forced-draft unit served by a feedwater deaerator and boiler feedwater pump system. It will be equipped with an economizer to maximize fuel efficiency.

The auxiliary boiler will be equipped with a low-NO_x combustor and an SCR system and CO catalyst to control NO_x and CO concentrations in the exhaust gas. The boiler will exhaust through a free-standing 100-foot-tall steel stack.

2.2.5 Major Electrical Equipment and Systems

The bulk of the electric power produced by the facility will be transmitted to the Western, MID, TID, and PG&E grids. A small amount of electric power will be used onsite to power auxiliaries such as pumps and fans, control systems, and general facility loads including lighting, heating, and air conditioning. Some 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 subsections.

2.2.5.1 AC Power—Transmission

Power will be generated by the three CTGs and one STG at 18 kV and then stepped up by four transformers to 230 kV for transmission to the grid. An overall single-line diagram of the facility's electrical system is shown on Figure 2.2-5. The 18-kV generator outputs will be connected by an isolated-phase bus to oil-filled generator step-up transformers that increase the voltage to 230 kV. Surge arresters will be provided at the high-voltage bushings to protect the transformers from surges on the 230-kV system caused by lightning strikes or other system disturbances. The transformers will be set on concrete pads within containments designed to contain the transformer oil in the event of a leak or spill. Fire protection systems will be provided. The high-voltage side of the step-up transformers will be connected via overhead cables to the plant's 230-kV switchyard. From the switchyard, power will be transmitted via transmission line jointly owned by MID and TID.

The jointly owned MID/TID 230-kV line is located just across Kelso Road from the project site, and connects to the Tracy substation. This line will be connected to the new switchyard by the addition of 0.5 mile of two new electrical transmission lines, on two parallel structures, with each structure bearing two circuits. The two circuits between the new switchyard and Tracy substation will be separated, thereby providing two separate circuit connections from EAEC to Western's Tracy substation. A detailed discussion of the transmission system is provided in Section 5.0. The two existing transmission lines are currently operated as a single circuit. Two additional 0.5-mile transmission lines will connect the plant's switchyard with Western's existing Tracy substation.

2.2.5.2 AC Power—Distribution to Auxiliaries

Auxiliary power to the combustion turbine and steam turbine power block will be supplied at 4,160 volts AC by a double-ended 4,160-volt switchgear lineup. Primary power to the switchgear will be supplied by two oil-filled, 18-kV to 4.16-kV unit auxiliary/station service stepdown transformers. The high-voltage side (18-kV) of the unit auxiliary/ station service transformers will be connected to the outputs of two of the three CTGs. This connection will allow the switchgear to be powered from either or both of the two CTGs or by back-feeding power from the 230-kV switchyard. Low-voltage side (18-kV) generator circuit breakers will be provided for the two CTGs capable of feeding power to the 4,160-volt switchgear. These circuit breakers, used to isolate and synchronize the generators, will be located between the generators and the connections to the unit auxiliary/station service transformers. A natural-gas-fired emergency generator will be provided to supply power to emergency loads and auxiliary boiler loads when power is not available through the 230-kV interconnection to the grid.

The 4,160-volt switchgear lineup supplies power to the various 4,160-volt motors, to the combustion turbine starting system, and to the load centers (LC) transformers rated 4,160 to 480 volts for 480-volt power distribution. The switchgear will have vacuum interrupter circuit breakers for the main incoming feeds and fused switches for power distribution.

The LC transformers will be oil-filled, each supplying 480-volt, three-phase power to the double-ended load centers.

The load centers will provide power through feeder breakers to the various 480-volt motor control centers (MCCs). The 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. Transformation of 480-volt power to 120/208-volt power will be provided by 480-120/208-volt dry-type transformers.

2.2.5.3 125-volt DC Power Supply System

One common 125-volt DC power supply system consisting of one 100 percent capacity battery bank, two 100 percent static battery chargers, a switchboard, and two or more distribution panels will be supplied for balance-of-plant and STG equipment. Each CTG and the switchyard protection relay panel will be provided with their own separate battery systems and redundant chargers.

Under normal operating conditions, the battery chargers supply DC power to the DC loads. The battery chargers receive 480-volt, three-phase AC power from the AC power supply (480-volt) system and continuously load 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 supply DC power to the DC power supply 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 125-volt DC system will also be used to provide control power to the 4,160-volt switchgear, to the 480-volt LCs, to critical control circuits, and to the emergency DC motors.

2.2.5.4 Uninterruptible Power Supply System

The combustion turbines and steam turbine power block will also have an essential service 120-volt AC, single-phase, 60-hertz (Hz) uninterruptible power supply (UPS) to supply AC power to essential instrumentation, to critical equipment loads, and to 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, two static transfer switches, 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 CEMS equipment, DCS controllers, and input/output (I/O) modules will be fed using either UPS or 125-volt DC power directly.

2.2.6 Fuel System

The CTGs and auxiliary boiler will be designed to burn natural gas. Natural gas requirements during base load operation are approximately 5,000 million Btu/hr (LHV basis). Maximum natural gas requirements during peak load operation are approximately 7,200 million Btu/hr (LHV basis).

The expected pressure of natural gas delivered to the site via pipeline (see Section 6.0) will be 600 to 800 psig. The HP natural gas will flow through gas scrubber/filtering equipment, a gas pressure control station, a fuel gas heater, and a flow-metering station prior to entering the combustion turbines. Low-pressure gas for the emergency generator, auxiliary boiler, and HRSG duct burner systems will be provided by a central pressure reduction station and an LP gas distribution system.

2.2.6.1 Alternative Natural Gas Supply Routes

The preferred alternative and three alternative routes were considered for the natural gas supply, and are described below.

Alternative 2a. This route (preferred) is approximately 1.4 miles long. It begins at the project site, proceeds south on Mountain House Road, crosses Kelso Road and turns west to proceed parallel along the road, then crosses the road to the north and joins with PG&E main pipeline inside the compressor station.

Alternative 2b. Alternative 2b was a gasline route that was considered during project scoping but was determined to have greater environmental impacts than the other alternative routes.

Alternative 2c. This route is approximately 1.4 miles long and ties into the PG&E main pipeline near the corner of Kelso and Bruns. From the project site, the pipeline runs south on Mountain House Road to the corner of Kelso Road. From there, the route turns southwest at approximately 260 degrees for approximately 0.4 mile until it crosses the Delta-Mendota Canal. From that point it turns northwest at approximately 280 degrees to meet the PG&E main pipeline near the corner of Kelso and Bruns. Construction would be primarily by open trench, but might require HDD or bore and jack where it crosses the Delta-Mendota Canal, Canal 45, and any jurisdictional wetlands.

Alternative 2d. This route is approximately 1.5 miles long and ties into the PG&E main pipeline approximately 1.1 mile south of Kelso Road. From the project site, the pipeline runs south on Mountain House Road to the corner of Kelso Road. From there it turns southwest at approximately 250 degrees for approximately 0.3 mile until it crosses BBID's Canal 45. From that point it turns south for a distance of approximately 0.8 mile, primarily following the edge of the section line. Approximately 300 feet north of the PG&E pipeline, it takes the shortest and most efficient route to the pipeline, potentially heading directly west, or directly south, as determined by site-specific engineering constraints and consultations with PG&E. Construction would be primarily by open trench, but might require HDD or bore and jack where it crosses any jurisdictional wetlands.

Alternative 2e. This route is approximately 1.2 miles long and ties into the PG&E main pipeline approximately 0.8 mile south of Kelso Road, near where the Delta-Mendota Canal emerges from an underground aqueduct into an open canal. From the project site, the pipeline runs south on Mountain House Road to the corner of Kelso Road. From there it turns southwest at approximately 250 degrees for approximately 0.3 mile until it crosses BBID's Canal 45. From that point it turns approximately 195 degrees, to parallel the buried Delta-Mendota Canal for approximately 0.7 mile. The pipeline runs parallel to the Delta-Mendota Canal from 50 to 250 feet from the toe of the canal berm, as determined by final engineering and consultations with both Delta-Mendota and the landowner. Construction would be primarily by open trench, but might require HDD or bore and jack where it crosses any jurisdictional wetlands.

2.2.7 Water Supply and Use

This section describes the quantity of water required, the source(s) of the water supply, and water treatment requirements. A total of six water balance diagrams are included, representing two operating conditions for three sources of water (Figures 2.2-6a through 2.2-6f) . The two operating conditions represented are: (1) annual average operation at 61° F with three CTGs operating at 100 percent load, no HRSG duct firing, no CTG inlet air fogging, and no CTG power augmentation steam injection; and (2) peak operation at 98° F with three CTGs operating at 100 percent load, maximum HRSG duct firing, CTG inlet air fogging, and CTG power augmentation steam injection. The three water sources for which water balances are provided are: (1) 100 percent BBID raw water (Figures 2.2-6a and 2.2-6d); (2) 100 percent recycled water for cooling tower makeup with BBID raw water for supplemental process makeup (Figures 2.2-6b and 2.2-6e); and (3) 50 percent BBID raw water/50 percent recycled water for cooling tower makeup with BBID raw water for supplemental process makeup (Figures 2.2-6c and 2.2-6f).

During the initial years of plant operation, raw water for cooling tower and process makeup water will be provided by BBID. As the community of Mountain House is developed and recycled water becomes available, recycled water will supplement raw water resulting in a reduction in raw water use. By the year 2024, it is estimated that 50 percent of the project's need will be supplied by recycled water. During normal operation, distillate from the zero-liquid discharge treatment system will be used as process makeup to the demineralized water system. During peak operation, insufficient distillate is available from the zero-liquid discharge treatment system and additional makeup water is needed. Because of water quality requirements, raw water will always be the source for supplemental process makeup water. Potable water for sinks, showers, toilets, and eye wash/safety showers will be provided by a new onsite well or connections to a domestic supplier.

2.2.7.1 Water Requirements

A breakdown of the estimated average daily quantity of water required is presented in Table 2.2-1. The daily water requirements shown are estimated quantities based on the combined cycle plant operating at a constant 820 MW at an ambient temperature of 61°F without duct firing or steam injection. Peak water requirements shown in Table 2.2-2 are based on the plant operating at a constant 1,065 MW at an ambient temperature of 98°F with maximum duct firing and steam injection. The water balances and water requirements for the peak condition reflect the use of CTG power augmentation steam injection on a continuous basis. The plant would be expected to operate with less than 12 hours per day of steam injection.

TABLE 2.2-1
Estimated Average Daily Water Requirements at 61°F

Source Water	Daily Requirements (1,000s gallons)
100 percent BBID Raw Water	3,992 (2,772 gpm)
100 percent Recycled Water for Cooling Tower Makeup – BBID Raw Water for Supplemental Process Makeup	4,015 (2,788 gpm)
50 percent BBID Raw Water/50 percent Recycled Water for Cooling Tower Makeup – BBID Raw Water for Supplemental Process Makeup	4,000 (2,778 gpm)

TABLE 2.2-2
Estimated Peak Daily Water Requirements at 98°F

Source Water	Daily Requirements (1,000s gallons)
100 percent BBID Raw Water	9,104 (6,322 gpm)
100 percent Recycled Water for Cooling Tower Makeup – BBID Raw Water for Supplemental Process Makeup	9,174 (6,371 gpm)
50 percent BBID Raw Water/50 percent Recycled Water for Cooling Tower Makeup – BBID Raw Water for Supplemental Process Makeup	9,125 (6,337 gpm)

2.2.7.2 Water Supply

During normal operation, approximately 99 percent of the total water requirements for the EAEC are for cooling water that is used to condense steam discharging from the steam turbine. The cooling water is then circulated through the cooling tower to transfer the heat gained from condensing the steam into the atmosphere. During peak operation (maximum HRSG duct firing, CTG inlet air fogging, and CTG power augmentation steam injection), approximately 86 percent of the total water requirements are for cooling water makeup.

The remaining water needed for the plant is for process makeup water for the HRSGs, CTG inlet air fogging, CTG power augmentation steam, miscellaneous leaks and drains, plant general service water, and potable water for domestic use.

2.2.7.3 Alternatives for Water Supply Conveyance

Several possible alternatives for the BBID raw water pipeline route and the MHCSD WWTP recycled water pipeline route were evaluated. These alternatives are described in detail below, and shown in Figure 2.2-1.

BBID Raw Water Conveyance. Four BBID water supply conveyance alternatives from the intersection of Canal 45 and Bruns Road to the project site are presented in this section. Three alternatives involve the installation of a pump station on the south side of Bruns Road and a 24-inch pipeline. One additional alternative involves widening BBID's existing Canals 45 and 70 and installing a downstream pump station.

Alternative 3a. This alternative involves the installation of a pump station at the southern intersection of Canal 45 and Bruns Road. Approximately 2.6 miles of 24-inch pipeline would be installed northward along Bruns Road and then southeast along Byron Bethany Road to the project site. The pipeline would cross a high-pressure oil pipeline along Byron Bethany Road and the large box culverts that route the Delta-Mendota Canal water under Byron Bethany Road. The tops of these box culverts are approximately 12 feet below ground surface. Therefore, the pipeline could be installed over the culverts, avoiding the need to use trenchless technology. In addition, to reach the project site, the route would cross Mountain House Road using opencut construction technology.

Alternative 3b. This alternative transports the BBID raw water to the project site via BBID's Canals 45 and 70 from the existing BBID pump station on the north side of Bruns Road to Mountain House Road. At the intersection of Canal 70 and Mountain House Road, a pump station and pipeline would be installed to convey the water across and then along Mountain House Road northward to the EAEC. The pump station would be similar to that for Alternative 3a (Section 7.1.1.1). It would be built adjacent to the canal, and would have three pumps with identical capacity to those described above, but would operate at a total dynamic head of approximately 90 feet. Widening part or all of the 2.8-mile section of canal or lining portions of the canal might be necessary.

Alternative 3d. Similar to Alternative 3a, this alternative would require a pump station at Canal 45 and Bruns Road. It would also require 2.4 miles of 24-inch pipeline. The pipeline would be installed southward along Bruns Road for approximately 0.5 mile, then along an existing gravel road that runs east to the Delta-Mendota Canal, and then north to Byron Bethany Road along the canal. The pipeline would then be installed south along Byron Bethany Road and cross Mountain House Road to reach the project site. The pipeline would cross one high-pressure oil pipeline, Canal 45 along the gravel road, and large box culverts that route the Delta-Mendota Canal water under Byron Bethany Road.

Alternative 3e (Preferred Alternative). Similar to Alternative 3a, this alternative would require a pump station at Canal 45 and Bruns Road. It would also require 2.1 miles of 24-inch pipeline. The pipeline would be installed southward along Bruns Road for approximately 0.5 mile, then along an existing gravel road that runs east to the Delta-Mendota Canal, and then under the Delta-Mendota Canal and across Mountain House Road to reach the project site. The pipeline would cross one high-pressure oil pipeline and Canal 45 along the gravel road, and it would require trenchless technology to route under the Delta-Mendota Canal.

Conveyance of MHCSD WWTP Recycled Water. Two alternatives to convey water from the MHCSD WWTP to the project are presented in this section. Both alternatives include installing a pipeline and pump station adjacent to the future MHCSD WWTP. The pump station is described in Section 7.1.2, Recycled Water Supply. The maximum amount of water available from the MHCSD WWTP that could be used by EAEC (i.e., 700 AF /month [January]; 5,500 gallons per minute [gpm] peak instantaneous flow) would be transported via a 24-inch pipeline to the EAEC area and used by EAEC and, potentially, other BBID users.

Under each alternative, the pipeline would cross two existing creek beds and the Union Pacific Railroad (UPRR) along Byron Bethany Road where there are high-pressure oil pipelines. Each alternative would require trenchless construction methods.

Alternative 4a. The pump station would be sized to provide 350 to 700 AF per month as discussed in Section 7.1.2, Recycled Water Supply. This alternative would include approximately 4.3 miles of 24-inch pipeline installed from the site of the future MHCSD WWTP, west along Bethany Road, northwest along Byron Bethany Road, and west on Kelso Road to the project site. (The alignment along Kelso Road would be in accordance with the final configuration of Kelso Road, as determined by the Mountain House Community Services District.)

Alternative 4b (Preferred Alternative). This alternative would be sized to provide 350 to 700 AF per month directly to the project site. The pump station would be sized as discussed below in Section 7.1.2, Recycled Water Supply. This alternative would include approximately 4.6 miles of 24-inch pipeline installed from the site of the future MHCSD WWTP, west along Bethany Road, and then northwest along Byron Bethany Road to the project site.

2.2.7.4 Water Quality

An analysis of the water quality from BBID is provided in Section 8.14, Water Resources. Section 8.14 also includes a projection of the recycled water quality based on data from existing wastewater treatment plants located in areas using similar raw water sources.

2.2.7.5 Water Treatment

Figures 2.2-6a through 2.2-6f illustrate the water treatment and distribution system. 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 includes all other miscellaneous uses; (3) demineralized water for makeup to the HRSGs and auxiliary boilers; 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. Makeup water for the circulating water system will be a combination of raw and recycled water. This water will be fed directly into two 5-million-gallon aboveground storage tanks without pretreatment. These tanks will serve the following purposes: (1) the tanks will provide approximately 24 hours of operational storage for a maximum flow of 6,371 gpm in the event that there is a disruption in the flow of raw or recycled water; (2) the tanks allow a means to provide an air gap to protect BBID's raw water supply from potential contamination by recycled water or plant circulating water; and (3) the tanks will provide 2 hours of fire protection water storage at a flow rate of 2,000 gpm. Makeup water will be fed from the storage tanks to the cooling tower basin as required to replace water lost from evaporation, drift, and blowdown.

A chemical feed system will supply water conditioning chemicals to the circulating water to minimize corrosion and control the formation of mineral scale and biofouling. Sulfuric acid will be fed into the circulating water system in proportion to makeup water flow for alkalinity reduction to control the scaling tendency of the circulating water.

The acid feed equipment will consist of a bulk sulfuric acid storage tank and two full-capacity sulfuric acid metering pumps.

To further inhibit scale formation, a polyacrylate solution will be fed into the circulating water system as a sequestering agent in an amount proportional to the circulating water blowdown flow. The scale inhibitor feed equipment will consist of a chemical solution bulk storage tank and two full-capacity scale inhibitor metering pumps.

To prevent biofouling in the circulating water system, sodium hypochlorite will be fed into the system as a biocide. The hypochlorite feed equipment will consist of a bulk storage tank and two full-capacity hypochlorite metering pumps. Systems will also be provided for the feeding of alternate biocides. A bulk storage tank and two full-capacity metering pumps will be provided for the feeding of either stabilized bromine or sodium bromide. Facilities for feeding a non-oxidizing biocide will include 200- to 400-gallon totes and two full-capacity chemical metering pumps.

Service Water. Service water includes all water uses at the plant except for the circulating water previously discussed, demineralized water used in the HRSG and auxiliary boiler, and potable water (see following section). Softened and filtered cooling tower blowdown will be used for service water. Service water will be stored in an aboveground steel tank.

Makeup Water for the HRSGs and Auxiliary Boiler. Demineralized water will be used for makeup water for the HRSGs and auxiliary boiler. The demineralized water will be produced by passing distillate through offsite regenerated mixed bed ion exchange demineralizers. The source of distillate will be from one of the following: (1) during normal operation, sufficient distillate will be produced by the brine concentrator, which is part of the zero-liquid discharge system that recovers water from the cooling tower blowdown; (2) during peak load operation, the quantity of brine concentrator distillate will be insufficient to meet the demands for makeup to the demineralized water system. In this case, the brine concentrator distillate will be supplemented with raw water that has been filtered and purified via a reverse osmosis system to remove suspended solids and the majority of the dissolved solids. The demineralized water will be stored in two 500,000-gallon demineralized water storage tanks.

HRSG and auxiliary boiler makeup water will be drawn from the demineralized water storage tanks. Demineralized water will also be used for CTG inlet air fogging (used to increase turbine output) and for CTG wash water.

Additional conditioning of the water in the HRSGs and auxiliary boiler, to minimize corrosion and scale formation, will be provided by chemical feed systems. The systems will feed an oxygen scavenger to the condensate for dissolved oxygen control, a neutralizing amine to the condensate for corrosion control, and a phosphate solution to the HRSG steam drums for pH and alkalinity control. The design will provide for automatic feed of the oxygen scavenger in proportion to condensate flow and the amine in proportion to condensate flow with a pH bias. The system will include an oxygen scavenger solution feed tank and two full-capacity, chemical feed pumps and an amine solution feed tank and two full-capacity chemical feed pumps.

The phosphate feed system will be designed for operation using the low solids, congruent phosphate or other standard method of boiler water treatment. The design will provide for feeding phosphates to the boiler water to react with any hardness present. For congruent phosphate treatment, a dilute solution of a disodium phosphate/trisodium phosphate/hexameta phosphate mixture will be manually prepared in a phosphate solution tank dedicated to the HP and IP steam drums. The phosphate feed will be manually initiated based on boiler water phosphate residual and pH. One solution tank and full-capacity phosphate feed pump will be provided for each steam (HP and IP) drum with one common spare pump serving each HRSG.

HRSG and Auxiliary Boiler Steam Cycle Sampling and Analysis System. This system will monitor the water quality at various points in the HRSG and auxiliary boiler steam cycle and provide sufficient data to operating personnel for detection of deviations from control limits so that corrective action can be taken. The samples will be routed to a sample panel, located in the water treatment facility, where pressure and temperature will be reduced as required. At the sample panel, samples will be directed to automatic analyzers for continuous monitoring, and grab samples will be provided for wet chemical analysis. All monitored values will be indicated at the sample panel.

Automatic analyzers will monitor cation conductivity, pH, sodium, dissolved oxygen, and specific conductance.

2.2.8 Plant Cooling Systems

The cycle heat rejection system will consist of a deaerating steam surface condenser, cooling tower, and circulating water system. The heat rejection system will receive exhaust steam from the low-pressure steam turbine and condense it 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 cooling water flowing in one or more passes inside the tubes. The condenser will be designed to operate at sub-atmospheric pressure, ranging from 1.0 to 5.0 inches of mercury, absolute (in Hga.), depending on ambient temperature and plant load. It will remove between 1,700 and 3,000 MMBtu/hr, depending on ambient temperature and plant load. Approximately 267,300 gpm of circulating cooling water is required to condense the steam at maximum plant load.

The circulating water will circulate through a counter-flow mechanical draft cooling tower, which uses electric-motor-driven fans to move the air in a direction opposite to 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 some of the circulating water. Maximum drift, that is, the fine mist of water droplets entrained in the warm air leaving the cooling tower, will be limited to 0.0005 percent of the circulating water flow.

A closed-loop auxiliary cooling system will be provided for cooling plant equipment other than the steam condenser. Equipment served by the auxiliary cooling water system includes the CTG and STG lube oil coolers, STG generator cooler, STG hydraulic control system cooler, boiler feed pump lube oil and seal water coolers, air compressor, vacuum pump seal coolers, and sample coolers. Auxiliary cooling water pumps will pump circulating water from the cooling tower basin through heat exchangers to remove heat from the closed loop system.

2.2.9 Waste Management

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

2.2.9.1 Wastewater Collection, Treatment, and Disposal

There are two separate wastewater collection systems. The first and primary system will collect process wastewater from all of the plant equipment, including the HRSGs, cooling tower, and water treatment equipment. The water balance diagrams, Figures 2.2-6a through 2.2-6f, show the expected wastewater streams and flow rates for the EAEC. Since the EAEC is a zero-liquid discharge facility, process wastewater will be reclaimed and reused, to the extent possible. The leftover concentrated brine solution, high in total dissolved solids (TDS), will be directed to onsite evaporation ponds. The second system will collect sanitary wastewater from sinks, toilets, showers, and other sanitary facilities, and discharge it to an onsite septic tank and leach field.

The wastewater system is described below.

Circulating Water System Blowdown. Circulating water system blowdown will consist of raw and/or recycled water from BBID along with various process waste streams that have been concentrated between three and eight times and residues of the chemicals added to the circulating water. These chemicals control scaling and biofouling of the cooling tower and control corrosion of the circulating water piping and condenser. Cooling tower blowdown will be discharged to a zero-liquid discharge treatment system, where the majority of the water will be reclaimed for reuse within the plant.

Zero-liquid Discharge Treatment System. Cooling tower blowdown will first pass through a reactor/clarifier. The reactor/clarifier will be a solids contact clarifier where sodium hydroxide (caustic) will be fed to the influent stream to precipitate calcium carbonate and reduce silica and magnesium concentrations. In addition to the sodium hydroxide, soda ash will be added to assist in the control of calcium; magnesium oxide will be added to assist in the removal of silica; and coagulants and polymer will be added to aid in the coagulation and sedimentation of suspended solids. The majority of the sludge produced by the process will be recirculated within the clarifier. The remaining sludge will be discharged to a sludge thickener followed by a filter press, producing a relatively dry filter cake suitable for landfill disposal.

Supernatant from the sludge thickener will be returned to the influent of the reactor/ clarifier. The reactor/clarifier effluent will next pass through sidestream filters to reduce suspended solids. The sidestream filters will consist of multimedia (sand/anthracite) filters with intermittent air/water backwash. The backwash wastewater will be discharged to an equalization basin, where it will slowly be fed to the sludge thickener. The filtered water will be collected in a storage tank, providing a source of water for backwashing the filters. Filtered water will next pass through a high TDS reverse osmosis (RO) system to remove the majority of the dissolved solids. The RO permeate will be recovered and used for cooling tower makeup. The high TDS RO reject stream will be fed to a brine concentrator. The RO reject stream will be concentrated in a brine concentrator. The brine concentrator high-purity distillate will be stored in a distillate storage tank where it will then be used as makeup for the demineralized water system. Excess distillate will overflow the storage tank and be recycled to the cooling tower basin. The concentrated brine solution, which represents the only process waste stream not reclaimed for reuse, will be discharged to the evaporation ponds. Two evaporation ponds, approximately 5 acres each, will be provided.

Evaporation Ponds. Concentrated brine from the cooling tower treatment system would be discharged to two 5-acre onsite evaporation ponds, located in the southern portion of the site. The ponds would require Waste Discharge Requirements (WDRs) issued by the Central Valley Regional Water Quality Control Board (CVRWQCB) as required by Title 27 of the California Code of Regulations. EAEC would apply for WDRs by filing a Report of Waste Discharge (ROWD) with the CVRWQCB prior to construction.

The project would have two ponds, so that one can be taken out of service for maintenance. The evaporation ponds would receive a waste stream from the evaporator of approximately 5 to 53 gallons per minute, depending on plant load and source water quality.

The evaporation ponds would be designed and engineered to meet the requirements of the applicable section of Title 27. Liquid wastes are generally required to be discharged to Class II surface impoundment and fitted with double liners. Title 27 further stipulates that Class II Units shall be designed, operated, and maintained to prevent inundation or washout due to floods with a 100-year return period.

The ponds would be designed to have the following characteristics and sufficient depth to allow for:

- Storage of the entire salt production for a period of 30 years.
- Water level variations throughout the year as a result of changes in plant inflow, rainfall, and evaporation rates.
- Increases in water level when the evaporation rate is 90 percent of the mean evaporation rate for 2 successive years.
- Increases in the water level during pond maintenance, which assumes one cell will need maintenance for a period of 2 months.
- Increases in water level in the case of a 100-year rainfall event on top of the maximum water level resulting from water level variations.
- Freeboard above the maximum water level to provide the greater of 24 inches or the height of the wind wave run-up plus 12 inches.
- Two liners will be used; the outer and inner layers will be covered with high-density polyethylene (HDPE) geomembrane material. The pond influent system will be designed so that each cell can operate independently should a shutdown for maintenance reasons be necessary.

Monitoring requirements would include the following:

- Evaporation wastewater basin
- Evaporation sludge

- Groundwater
- Leachate collection and recovery system
- Vadose zone

The location of groundwater and vadose zone monitoring would be provided in the ROWD, and would be developed in consultation with the CVRWQCB. The ROWD would also discuss the type and frequency of sampling and the constituents analyzed for each type of sample. Sample collection, storage, and analysis would be performed by State-approved labs in accordance with USEPA-approved methods or by using the most recent edition of Standard Methods for the Examination of Water and Wastewater. The CVRWQCB would approve all alternative methods of analysis.

Plant Drains and Oil/Water Separator. Miscellaneous general plant drains will collect area washdown, sample drains, equipment leakage, and drainage from facility equipment areas. 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 oil/water separator. Water from the plant wastewater collection system will be recycled to the cooling tower basin. Wastewater from combustion turbine water washes will be collected in a holding tank. If cleaning chemicals were not used during the water wash procedure, the wastewater will be discharged to the oil/water separator. Wastewater containing cleaning chemicals will be trucked offsite for disposal at an approved wastewater disposal facility.

Power Cycle Makeup Water Treatment Wastes. Wastewater from the power cycle makeup water treatment system will consist of the reject stream from the makeup RO units that will initially reduce the concentration of dissolved solids in the plant makeup water before it is treated in the mixed bed ion exchange vessels and backwash water from the multi-media filters upstream of the RO units. The RO reject stream will contain the constituents of the BBID raw water, concentrated approximately five times; residues of the chemicals such as aluminum sulfate, ferric chloride, and polymer added to the raw water to coagulate suspended solids prior to filtration; sodium bisulfite or sodium sulfite added to the RO feedwater to eliminate free chlorine that would otherwise damage the RO membranes; and phosphate to prevent scaling of the membranes. The filter backwash water will contain the suspended solids removed from the raw water and residues of the coagulants used to enhance filtration efficiency. These waste streams will be collected and recycled to the cooling tower basin along with the plant drains and permeate from the high TDS RO units.

HRSG and Auxiliary Boiler Blowdown. HRSG blowdown will consist of boiler water discharged from the HRSG steam drums to control the concentration of dissolved solids and silica within acceptable ranges. Boiler blowdown will be discharged to flash tanks where the steam is vented to atmosphere and the condensate is cooled by mixing it with a small amount of circulating water. The quenched condensate will be discharged to the cooling tower basin, thus reclaiming the majority of the boiler blowdown.

2.2.9.2 Solid Wastes

The EAEC 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 miscellaneous solid wastes including the typical refuse generated by workers. These materials will be collected by the local waste disposal company (see Section 8.13). Recyclable materials will be taken offsite. Waste collection and disposal will be in accordance with applicable regulatory requirements to minimize health and safety effects.

2.2.9.3 Hazardous Wastes

Several methods will be used to properly manage and dispose of hazardous wastes generated by the EAEC. Waste lubricating oil will be recovered and recycled by a waste oil recycling contractor. Spent lubrication oil filters will be disposed of in a Class I landfill. Spent SCR and oxidation catalysts will be recycled by the supplier or disposed of in a Class I landfill. Workers will be trained to handle hazardous wastes generated at the site.

Chemical cleaning wastes will consist of alkaline and acid cleaning solutions used during pre-operational chemical cleaning of the HRSGs, acid cleaning solutions used for chemical cleaning of the HRSGs after the units are put into service, and turbine wash and HRSG fireside washwaters. These wastes, which are subject to high metal concentrations, will be temporarily stored onsite in portable tanks, and disposed of offsite by the chemical cleaning contractor in accordance with applicable regulatory requirements.

2.2.10 Management of Hazardous Materials

There will be a variety of chemicals stored and used during construction and operation of the EAEC project. The storage, handling, and use of all chemicals will be conducted in accordance with applicable laws, ordinances, regulations, and standards. Chemicals will be stored in appropriate chemical storage facilities. Bulk chemicals will be stored in storage tanks, and 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 volatile 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 cooling tower basin.

The anhydrous ammonia storage area will have a water spray system, spill containment, and ammonia vapor detection equipment.

Safety showers and eyewashes will be provided adjacent to or in the vicinity of all chemical storage and use areas. Hose connections will be provided near the chemical storage and feed areas to flush spills and leaks to the plant wastewater collection system. State-approved personal protective equipment will be used by plant personnel during chemical spill containment and cleanup activities. Personnel will be properly trained in the handling of these chemicals and instructed in the procedures to follow in case of a chemical spill or accidental release. Adequate supplies of absorbent material will be stored onsite for spill cleanup.

Electric equipment insulating materials will be specified to be free of polychlorinated biphenyls (PCB).

A list of the chemicals anticipated to be used at the generating facility and their locations is provided in Table 8.12-2 of the Hazardous Materials Handling section. This table identifies each chemical by type, intended use, and estimated quantity to be stored on site. Section 8.12 includes additional information on hazardous materials handling.

2.2.11 Emission Control and Monitoring

Air emissions from the combustion of natural gas in the CTGs and duct burners will be controlled using state-of-the-art systems. Emissions that will be controlled include NO_x, reactive organic compounds (ROCs), CO, and particulate matter. To ensure that the systems perform correctly, continuous emissions monitoring (CEM) will be performed. Section 8.1, Air Quality, includes additional information on emission control and monitoring.

2.2.11.1 NO_x Emission Control

SCR will be used to control NO_x concentrations in the exhaust gas emitted to the atmosphere to 2.5 ppmvd at 15 percent oxygen from the gas turbines/HRSGs (2.0 ppmvd on an average annual basis) and 9 ppmvd at 3 percent oxygen from the auxiliary boiler. The SCR process will use anhydrous ammonia. Ammonia slip, or the concentration of unreacted ammonia in the exiting exhaust gas, will be limited to 5 ppmvd at 15 percent oxygen from the gas turbines/HRSGs and 10 ppmvd at 3 percent oxygen from the auxiliary boiler. The SCR equipment will include a reactor chamber, catalyst modules, ammonia storage system, ammonia vaporization and injection system, and monitoring equipment and sensors.

2.2.11.2 Carbon Monoxide

A CO catalytic converter will be used to reduce the CO concentration in the exhaust gas emitted to the atmosphere to 6 ppmvd at 15 percent oxygen from the gas turbines and 50 ppmvd at 3 percent oxygen from the auxiliary boiler.

2.2.11.3 Particulate Emission Control

Particulate emissions will be controlled by the use of combustion air filtration and the use of natural gas, which is low in particulates, as the sole fuel for the CTGs and auxiliary boiler.

2.2.11.4 Continuous Emission Monitoring

CEMs will sample, analyze, and record fuel gas flow rate, NO_x and CO concentration levels, and percentage of O_2 in the exhaust gas from the three HRSG stacks and from the auxiliary boiler stack. This system will generate reports of emissions data in accordance with permit requirements and will send alarm signals to the plant DCS when the emissions approach or exceed pre-selected limits.

2.2.12 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. There will be a dedicated fire water storage supply of a minimum of 240,000 gallons in the raw water storage tanks. The dedicated water supply is sized in accordance with National Fire Protection Association (NFPA) 850 to provide 2 hours of protection from the onsite worst-case single fire. The raw water storage tanks will include a standpipe on the cooling tower makeup supply line so that the dedicated fire water portion of the storage tanks cannot be used for other purposes.

An electric jockey pump and electric-motor-driven main fire pump will be provided to increase the water pressure in the plant fire mains to the level required to serve all fire fighting systems. In addition, a diesel engine-driven fire pump will be provided to pressurize the fire loop if the power supply to the main fire pump fails. A fire pump controller will be provided for the back-up fire pump.

All three fire pumps will discharge to a dedicated underground fire loop piping system. Both the fire hydrants and the fixed suppression systems will be supplied from the fire water loop. Fixed fire suppression systems will be installed at determined fire risk areas such as the transformers, turbine lube oil equipment, and the anhydrous ammonia storage tanks. Sprinkler systems will also be installed in the Administration/Maintenance Building and Fire Pump enclosure as required by NFPA and local code requirements. The CTG units will be protected by an FM200 fire protection system. Hand-held fire extinguishers of the appropriate size and rating will be located in accordance with NFPA 10 throughout the facility. The cooling tower will be constructed of fiberglass having a flame-spread rating of 25 or less and will therefore not be sprinklered.

Section 8.12, Hazardous Materials Handling, includes additional information for fire and explosion risk, and Section 8.8, Socioeconomics, provides information on local fire protection capability.

2.2.13 Plant Auxiliaries

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

2.2.13.1 Lighting

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

2.2.13.2 Grounding

The electrical system is susceptible to ground faults, lightning, and switching surges that result in high voltage that constitute a hazard to site personnel and electrical equipment. The station grounding system provides 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 heat from ground current 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 belowgrade in a grid pattern. Each junction of the grid will be bonded together by an exothermal welding process or mechanical clamps (see Appendix 10D.4, which refers to IEEE 837 compression connectors).

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

2.2.13.3 Distributed Control System

The Distributed Control System (DCS) provides 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, cathode ray tube [CRT]) for signals generated within the system or received from input/output (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 CRT(s), and recording on an alarm log printer
- Providing storage and retrieval of historical data

The distributed control system will be a redundant microprocessor-based system and will consist of the following major components:

- CRT-based operator consoles
- Engineer work station
- Distributed 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 work station 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 DCS 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 system 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.

2.2.13.4 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.

2.2.13.5 Freeze Protection

The freeze protection system will provide heating to protect various outdoor piping, gauges, pressure switches, and other devices from freezing. Power to the self-limiting freeze protection circuits will be controlled by an ambient thermostat.

2.2.13.6 Service Air

The service air system will 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.

2.2.13.7 Instrument Air

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

2.2.14 Interconnect to Electrical Grid

The three CTGs and one STG will each be connected to a dedicated three-phase step-up transformer (GSU) that will be connected to the plant 230-kV switchyard. The switchyard will consist of a breaker and one-half arrangement with SF_6 circuit breakers and manually operated disconnect switches on each side of each breaker A new 0.5-mile 230-kV double-circuit transmission line will interconnect the switchyard bus (Tracy B) with that of the existing Tracy substation (Tracy A). A separate double-circuit (operated as single circuit) 0.5-mile 230-kV transmission line will connect two existing MID/TID transmission lines to the new Tracy B switchyard (the MID/TID lines are presently connected to the existing Tracy Substation). See Section 5.0 for additional information on the switchyard, transmission line, and connection at the Western Tracy substation.

2.2.15 Project Construction

Construction of the generating facility, from site preparation and grading to commercial operation, is expected to take place from summer 2002 to the summer of 2004, or a total time of 24 months. Major milestones are listed in Table 2.2-3.

TABLE 2.2-3
Project Schedule Major Milestones

Activity	Date
Begin Construction	Second Quarter 2002
Startup and Test	First Quarter 2004
Commercial Operation	Second Quarter 2004

There will be an average and peak workforce of approximately 125 and 400, respectively, of construction craft people, supervisory, support, and construction management personnel on site during construction (Table 8.8-8).

Construction will be scheduled to occur between 6 a.m. and 6 p.m., Monday through Saturday. Additional hours may be necessary to make up schedule deficiencies, or to complete critical construction activities. 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 12 through Month 20 of the construction period.

Table 2.2-4 provides an estimate of the average and peak construction traffic during the 24-month construction period.

TABLE 2.2-4
Average and Peak Construction Traffic

Vehicle Type	Average Daily Trips	Peak Daily Trips
Construction Workers	143	350
Delivery	2	6
Heavy Trucks	5	20
Total	**150**	**376**

Construction laydown and parking areas will be within approximately 20 acres located on the EAEC site, north of the plant site. Construction access will be from Mountain House Road, as shown on Figure 2.2-3. Materials and equipment could be delivered by truck or rail.

2.2.16 Generating Facility Operation

The EAEC will be operated by three operators per 12-hour rotating shift, plus three relief operators and a chemical technician, seven maintenance technicians, and seven administrative personnel during the standard 8-hour work day. The facility will be operated 7 days a week, 24 hours per day.

EAEC Staffing Plan

Plant Manager	Maintenance Manager	Operations Manager		
Plant Engineer	I&E Technician	"A" Operator	"B" Operator	"C" Operator
Office Manager	I&E Technician	"A" Operator	"B" Operator	"C" Operator
Plant Administrator	I&E Technician	"A" Operator	"B" Operator	"C" Operator
Purchasing/Warehouse Technician	Electrical Technician	"A" Operator	"B" Operator	"C" Operator
	Maintenance Technician	"A" Operator	"B" Operator	"C" Operator
	Maintenance Technician	Chemical Technician		
	Maintenance Technician			

The EAEC is expected to have an annual availability in the general range of 92 to 98 percent. It will be possible for plant availability to exceed 98 percent for a given 12-month period. The exact operational profile of the plant, however, cannot be defined since the facility will be operating in and selling electricity to a deregulated electric power sales market.

The California electricity market was deregulated March 31, 1998. Independent power producers such as EAEC are now free to sell their electricity to all users including electric utilities, industrial and commercial firms, and residential users. The EAEC might be able to sell all or part of its generation under contract. Generation available from the EAEC that has not been sold through contracts will be available for sale on the spot market through a power exchange, which will work to match buyers and sellers of electricity. Operation of the EAEC therefore depends on the quantity of electricity sold through contracts and the ability of EAEC to sell into the competitive spot market.

Because the capacity that will be sold through contract and the prices that will be offered for spot purchases are unknown at this time, the exact mode of operation of the EAEC cannot be described. It is conceivable, however, that the facility could be operated in one or all of the following modes:

- **Base Load**. The facility would be operated at maximum continuous output for as many hours per year as is profitable. During high ambient temperature periods when gas turbine output would otherwise decrease, duct firing and/or power augmentation by steam injection into the combustion turbines may be employed to keep plant output at the sum of contractual load and spot market sales.
- **Load Following**. The facility would be operated to meet contractual load and whatever spot sales could be made, but the sum would be less than maximum continuous output at all times of the day. The output of the unit would therefore be adjusted periodically to meet whatever load proved profitable to the facility.
- **Partial Shutdown**. At certain times of any given day and at certain times of any given year, the sum of the contractual load and spot market sales can be expected to drop to a level at which it would be economically favorable to shut down one or two CTG(s)/HRSG(s). This mode of operation can be expected to occur during late evening and early morning hours and on weekends when contractual load could decrease or spot market sales would not be economical.
- **Full Shutdown**. This would occur if forced by equipment malfunction, fuel supply interruption, or transmission line disconnect. Full shutdown could also occur when the market price of electricity is less than the EAEC incremental cost of generation. The facility is limited in operation below maximum continuous output (base load) by economics since gas turbine efficiency decreases sharply as output is decreased. The facility will also experience operational problems including exceedance of air quality limits at outputs below 60 percent of CTG output.

In the unlikely event of a situation that causes a longer-term cessation of operations, security of the facilities will be maintained on a 24-hour basis, and the CEC will be notified. 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 laws, ordinances, regulations, and standards (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, decommissioning will be undertaken (see Section 4.0, Facility Closure).

2.3 Facility Safety Design

The EAEC 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.

2.3.1 Natural Hazards

The principal natural hazards associated with the EAEC site are earthquakes and flooding. The site is located in Seismic Risk Zone 4. Structures will be designed to meet the seismic requirements of CAC Title 24 and the 1997 Uniform Building Code (UBC). Section 8.15, Geologic Hazards and Resources, discusses the geological hazards of the area and site, and Appendix 10G contains the results of a geotechnical investigation of the EAEC project site. These sections include a review of potential geologic hazards, seismic ground motion, and potential for soil liquefaction due to ground-shaking. The investigation indicated geologic hazards were not expected at the project site. Appendix 10G and Appendix 10B, Structural Engineering, include the structural seismic design criteria for the buildings and equipment.

The site is essentially flat with an elevation of approximately 40 feet above mean sea level (msl). According to the Federal Emergency Management Agency (FEMA), the site is not within either the 100- or 500-year flood plain. Section 8.4, Land Use, includes additional information on the potential for flooding.

2.3.2 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 8.8, Socioeconomics, includes additional information on area medical services, and Section 8.7, Worker Safety, includes additional information on safety for workers. Appendices 10A through 10G contain the design practices and codes applicable to safety design for the project. Compliance with these requirements will minimize project effects on public and employee safety.

2.3.2.1 Fire Protection Systems

The project will rely on both onsite fire protection systems and local fire protection services.

Onsite Fire Protection Systems. The fire protection systems are designed to protect personnel and limit property loss and plant downtime from fire or explosion. The project will have the following fire protection systems.

FM 200 Fire Protection System. This system protects the combustion turbine, generator, and accessory equipment compartments from fire. The system will have fire detection sensors in all compartments. Actuating one sensor will provide a high-temperature alarm on the combustion turbine control panel. Actuating a second sensor will trip the combustion turbine, turn off ventilation, close ventilation openings, and automatically release the FM 200. The FM 200 will be discharged at a design concentration adequate to extinguish the fire.

Transformer Deluge Spray System. This system provides fire suppression for the generator transformers and auxiliary power transformers in the event of a fire. The deluge systems are fed by the plant underground fire water system.

Steam Turbine Bearing Preaction Water Spray System. This system provides suppression for the steam turbine bearing in the event of fire. The preaction system is fed by the plant underground fire water system.

Steam Turbine Lube Oil Areas Water Spray System. This system provides suppression for the steam turbine area lube oil piping and lube oil storage.

Fire Hydrants/Hose Stations. This system will supplement the plant fire protection system. Water will be supplied from the plant underground fire water/domestic water system.

Fire Extinguisher. The plant Administrative/Maintenance Building, water treatment facility, and other structures will be equipped with portable fire extinguishers as required by the local fire department.

Local Fire Protection Services. In the event of a major fire, the plant personnel will be able to call upon the Alameda County Fire Department for assistance. The Hazardous Materials Risk Management Plan (see Section 8.12, Hazardous Materials Handling) for the plant will include all information necessary to permit all fire-fighting and other emergency response agencies to plan and implement safe responses to fires, spills, and other emergencies.

2.3.2.2 Personnel Safety Program

The EAEC project 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. These programs are described in Section 8.7, Worker Safety.

2.4 Facility Reliability

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

2.4.1 Facility Availability

Because of EAEC's predicted high efficiency, 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 25 and 100 percent of base load to support dispatch service in response to customer demands for electricity.

The EAEC 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 combined-cycle power block (and the HRSG duct burners) 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, whether at full or partial load. The projected service factor for the combined-cycle power block, 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 EAEC is estimated to be approximately 92 to 98 percent.

The EAF, which is a weighted average of the percent of energy production capacity achievable, 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.

2.4.2 Redundancy of Critical Components

The following subsections identify equipment redundancy as it applies to project availability. A summary of equipment redundancy is shown in Table 2.4-1. Final design could differ.

TABLE 2.4-1
Major Equipment Redundancy

Description	Number	Note
Combined cycle CTGs and HRSGs	Three trains	Steam turbine bypass system allows all three CTG/HRSG trains to operate at base load with the steam turbine out of service.
STG	One	See note above pertaining to CTGs and HRSGs.
HRSG feedwater pumps	Two - 100 percent per HRSG	
Condensate pumps	Three - 50 percent capacity	
Condenser	One	Condenser must be in operation for combined cycle operation or operation of CTG in steam turbine bypass mode. The condenser will be provided with split water boxes to allow online tube cleaning and repair.
Circulating water pumps	Two - 50 percent capacity	
Cooling tower	One	Cooling tower is multi-cell mechanical draft design. Basin will be divided (8 cells/11 cells) to allow a portion to be isolated for cleaning.
Auxiliary cooling water pumps	Two - 100 percent capacity	
Closed-loop cooling water pumps	Two - 100 percent capacity	
Closed-cycle cooling water heat exchangers	Two - 100 percent capacity	
Demineralizer—RO Systems	Three - 50 percent capacity trains	Redundant pumps will be provided.
Brine concentrator	One - 100 percent capacity	When brine concentrator is out of service, the reject stream from the high TDS RO unit will be temporarily stored in the wastewater pond.

2.4.2.1 Combined-cycle Power Block

Three separate combustion turbine/HRSG power generation trains will operate in parallel within the combined-cycle power block. Each train will be powered by a combustion turbine. Each CTG will provide approximately 17 to 22 percent of the total combined-cycle power block output. The heat input from the exhaust gas from each combustion turbine will be used in the steam generation system to produce steam. Heat input to each HRSG can be supplemented by firing the HRSG duct burners, which will increase steam flow from the HRSG. Thermal energy in the steam from the steam generation system will be converted to mechanical energy, and then electrical energy in the STG subsystem. The expanded steam from the steam turbine will be condensed and recycled to the feedwater system. Power from the STG subsystem will contribute approximately 35 to 50 percent of total combined-cycle power block output.

The major components of the combined-cycle power block consist of the following subsystems.

CTG Subsystems. The combustion turbine subsystems include the combustion turbine, inlet air filtration and fogging system, generator and excitation systems, and turbine control and instrumentation. The combustion turbine will produce thermal energy through the combustion of natural gas and the conversion of the thermal energy into mechanical energy through rotation of the combustion turbine that drives the compressor and generator. Power output can be increased through steam injection upstream of the power turbine section of the CTG. Exhaust gas from the combustion turbine will be used to produce steam in the associated HRSG. The generator will be hydrogen cooled. 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, the protective system, and the sequence logic.

Steam Generation Subsystems. The steam generation subsystems consists of the HRSG, auxiliary boiler, and blowdown systems. The HRSG system provides for the transfer of heat from the exhaust gas of a combustion turbine and from supplemental combustion of natural gas in the HRSG duct burner for the production of steam. This heat transfer produces steam at the pressures and temperatures required by the steam turbine. Each HRSG system consists of ductwork, heat transfer sections, an SCR system, a CO catalyst module, and exhaust stack. The auxiliary boiler provides for STG gland steam, HRSG sparging steam, condenser hotwell sparging steam, and deaeration steam when the plant is off-line. 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.

STG Subsystems. The steam turbine converts the thermal energy in the main steam to mechanical energy to drive the STG. The basic subsystems include the steam turbine and auxiliary systems, turbine lube oil system, and generator/exciter system.

The combined-cycle power block is served by the following balance-of-plant systems.

2.4.2.2 DCS

The DCS will be a redundant microprocessor-based system that will provide control, monitoring, and alarm functions for plant systems and equipment. The following functions will be provided:

- Control the HRSGs, STG, CTG, and other systems in response to unit load demands (coordinated control)
- Provide control room operator interface

- Monitor plant equipment and process parameters and provide this information to the plant operators in a meaningful format
- Provide visual and audible alarms for abnormal events based on field signals or software-generated signals from plant systems, processes, or equipment

The DCS will have functionally distributed architecture comprising a group of similar redundant processing units linked to a group of operator consoles and an 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 DCS will interface with the control systems furnished by the combustion turbine and steam turbine suppliers to provide remote control capabilities, as well as data acquisition, annunciation, and historical storage of turbine and generator operating information.

The system will be designed with sufficient redundancy to preclude a single device failure from significantly affecting overall plant control and operation.

Consideration will be given to the action performed by the control and safety devices in the event of control circuit failure. Controls and controlled devices will move to the safest operating condition upon failure.

Plant operation will be controlled from the operator panel located in the control room. The operator panel will consist of two individual CRT/keyboard consoles and one engineering work station. Each CRT/keyboard console will be an independent electronic package so that failure of a single package does not disable more than one CRT/ keyboard. The engineering work station will allow the control system operator interface to be revised by authorized personnel.

2.4.2.3 Boiler Feedwater System

The boiler feedwater system transfers feedwater from the LP drum to the HP and IP sections of the HRSGs. The system will consist of two pumps per HRSG, each pump sized for 100 percent capacity for supplying one HRSG. The pumps 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.

2.4.2.4 Condensate System

The condensate system will provide a flow path from the condenser hotwell to the HRSG LP drum and boiler feed pumps. The condensate system will include three 50 percent capacity multistage, vertical, motor-driven condensate pumps.

2.4.2.5 Demineralized Water System

Makeup to the demineralized water system will be from one of the sources described in Section 2.2.7.2. The demineralized water system will consist of three 50 percent capacity makeup RO and mixed-bed demineralizer trains. Demineralized water will be stored in two 500,000-gallon demineralized water storage tanks.

2.4.2.6 Power Cycle Makeup and Storage

The power cycle makeup and storage subsystem provides demineralized water storage and pumping capabilities to supply high-purity water for system cycle makeup and chemical cleaning operations. Major components of the system are the demineralized water storage tanks, providing an approximate 18-hour supply of demineralized water at peak load or an approximate 9-day supply at base load (no duct firing or power augmentation), and two full-capacity, horizontal, centrifugal, cycle makeup water pumps.

2.4.2.7 Circulating Water System

The circulating water system provides cooling water to the condenser for condensing steam turbine exhaust and steam turbine bypass steam. In addition, the system supplies cooling water to the closed-cycle cooling water heat exchangers. Major components for this subsystem are two 50 percent, motor-driven vertical circulating water pumps, two 100 percent auxiliary cooling water pumps, and associated piping and valves, as required.

2.4.2.8 Closed-cycle Cooling Water System

The closed-cycle cooling water system transfers heat from various plant equipment heat exchangers to the circulating water system through the cooling water heat exchangers. Major components for this subsystem are two 100 percent, motor-driven centrifugal pumps, and two 100 percent cooling water heat exchangers.

2.4.2.9 Compressed Air

The compressed air system comprises the instrument air and service air subsystems. The service air system supplies compressed air to the instrument air dryers and to hose connections for general plant use. The service air system will include one 100 percent capacity air motor-driven compressor, service air headers, distribution piping, and hose connections. Exhaust bleed air from the three CTGs will be the normal source of compressed air. The motor-driven compressor will provide compressed air when the plant is off-line. The instrument air system supplies dry compressed air at the required pressure and capacity for all control air demands, including pneumatic controls, transmitters, instruments, and valve operators. The instrument air system will include two 100 percent capacity air dryers with prefilters and after filters, an air receiver, instrument air headers, and distribution piping.

2.4.3 Fuel Availability

Fuel will be delivered by PG&E from its Bethany Compressor Station, which is supplied by a high-pressure interstate transmission line carrying natural gas from Canada (see Section 6.0, Natural Gas Supply). There is sufficient capacity through the interstate line and at the terminal to supply the EAEC. It is conceivable that the transmission line or lines supplying the Bethany Compressor Station or the 20-inch connecting line to the EAEC could become temporarily inoperable due to a breach in the line or from other causes, resulting in fuel not being available at the EAEC. The EAEC has no backup supply of natural gas and would, therefore, have to shut down until the situation was corrected and gas became available through the lines again.

2.4.4 Water Availability

The primary source of makeup water for the EAEC will be raw water from the BBID. BBID issued a will-serve letter to the Applicant for 100 percent of its water needs for the EAEC (Appendix 8.14A). The availability of water to meet the needs of the EAEC is discussed in more detail in Section 7.0, Water Supply.

2.4.5 Project Quality Control

The Quality Control Program that will be applied to the EAEC 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 be 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, constructibility, and maintainability for the generation of electricity.

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.

2.4.5.1 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. The actual operation of the generating facility system.

As the project progresses, the design, procurement, fabrication, erection, and checkout of each generating facility system will progress through the nine stages defined above.

2.4.5.2 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, a list of qualified suppliers and subcontractors will be developed. Before contracts are awarded, the subcontractors' 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.

A plant operation and maintenance program, typical of a project this size, will be implemented by EAEC to control operation and maintenance quality. A specific program for this project will be defined and implemented during initial plant startup.

2.5 Laws, Ordinances, Regulations, and Standards

The applicable LORS for each engineering discipline are included as part of the Engineering Appendices 10A through 10F.

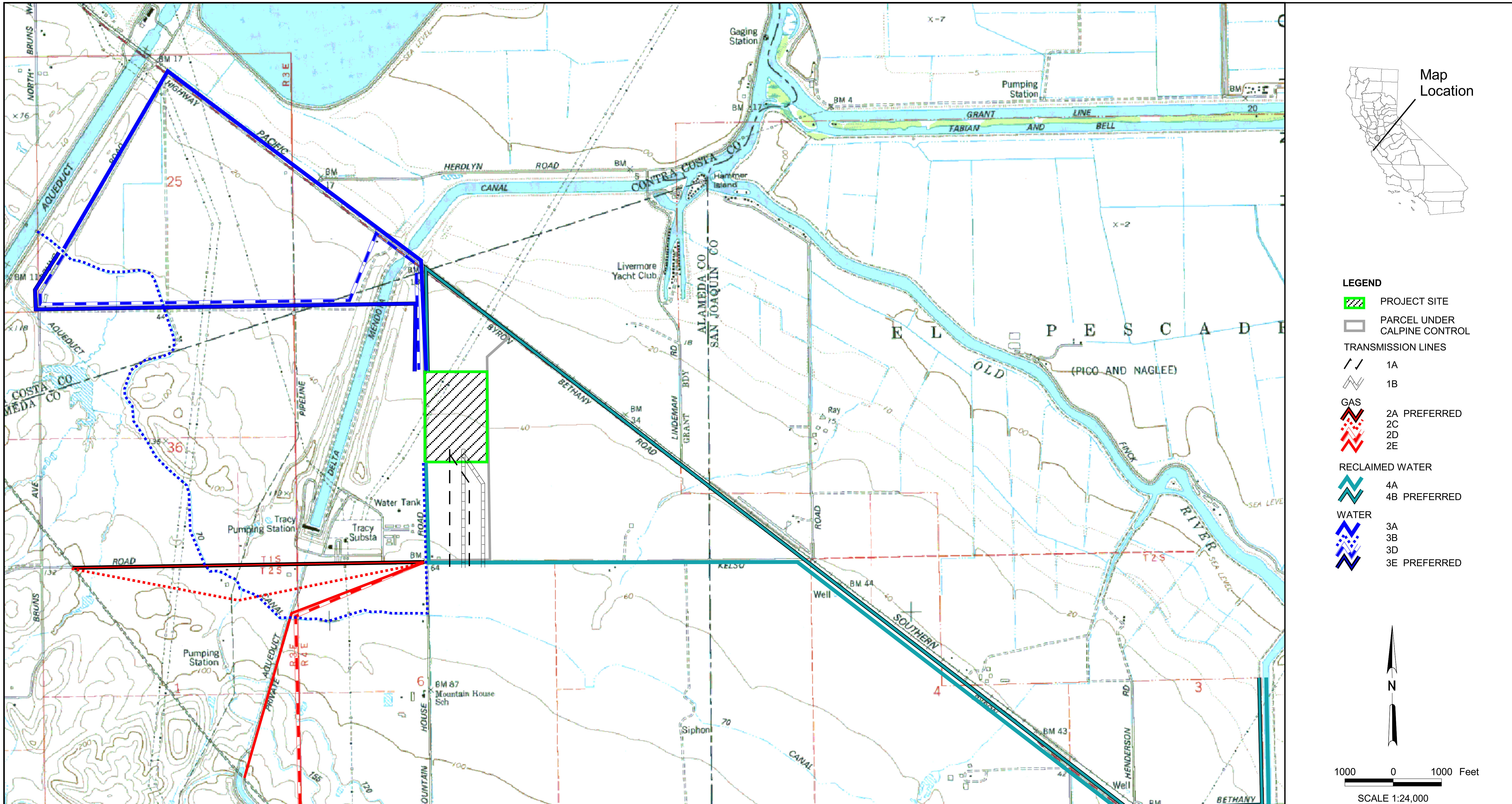


FIGURE 2.1-1
EAEC SITE AND LINEAR FACILITIES LOCATION MAP

APPLICATION FOR CERTIFICATION FOR EAST ALTAMONT ENERGY CENTER

CH2MHILL

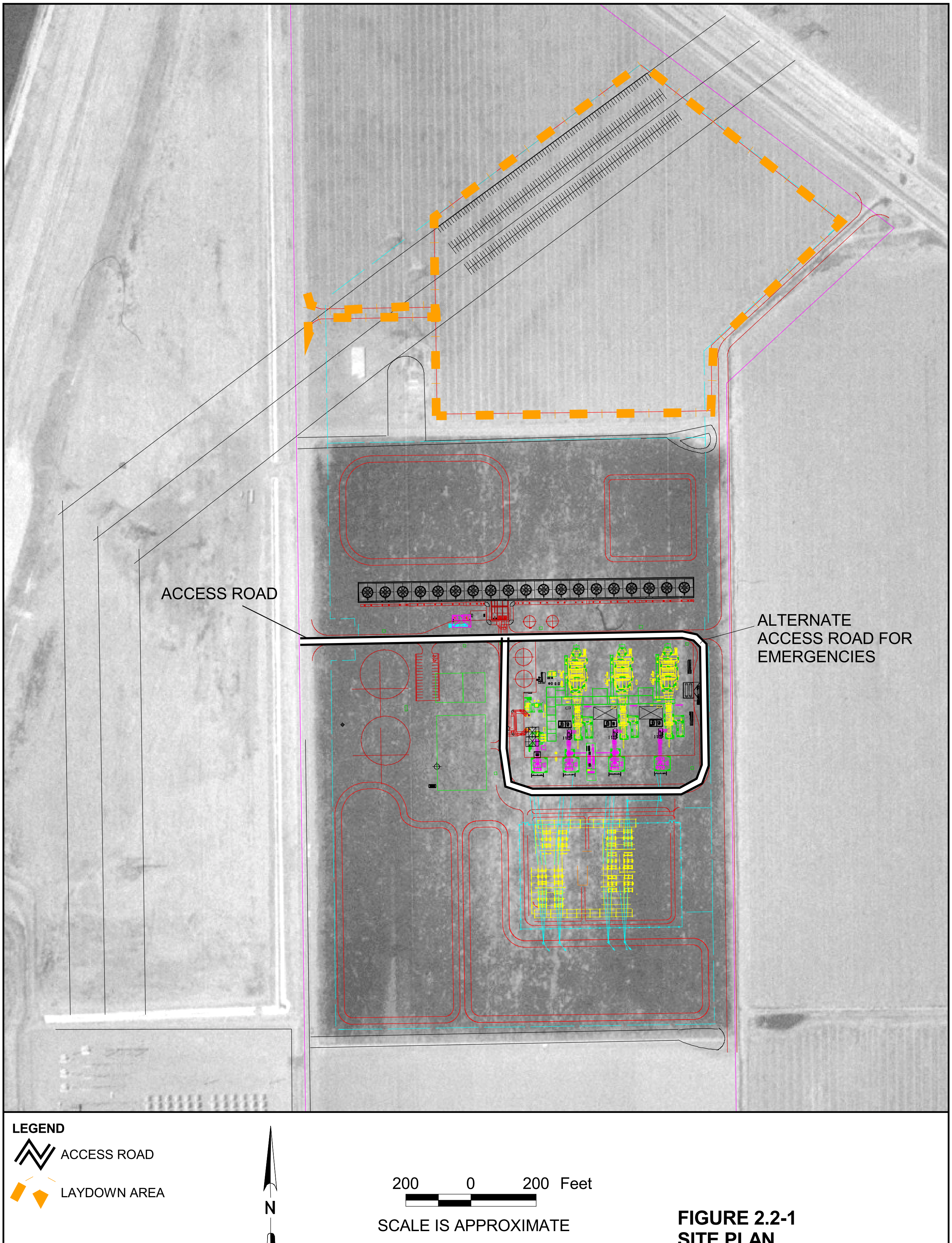


FIGURE 2.2-1
SITE PLAN

APPLICATION FOR CERTIFICATION
FOR EAST ALTAMONT ENERGY CENTER

CH2MHILL

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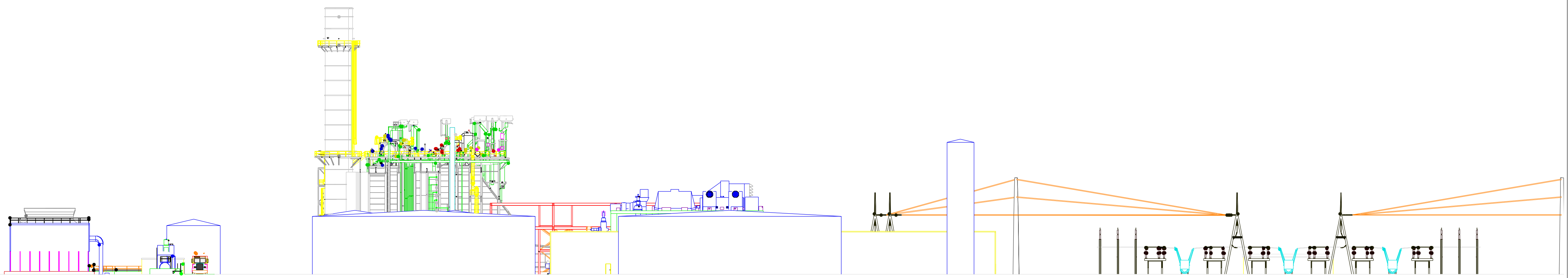
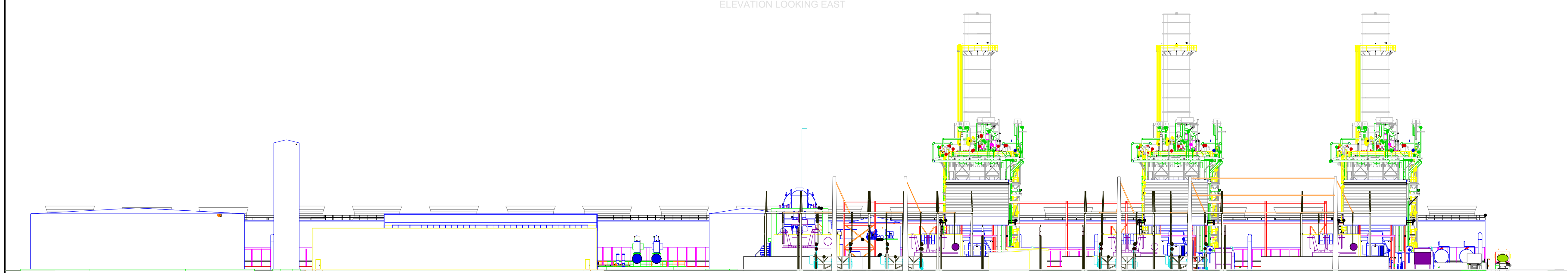


ELEVATION LOOKING EAST



ELEVATION LOOKING NORTH

N

SCALE IS APPROXIMATE

FIGURE 2.2-2
PLANT ELEVATION

APPLICATION FOR CERTIFICATION
FOR EAST ALTAMONT ENERGY CENTER

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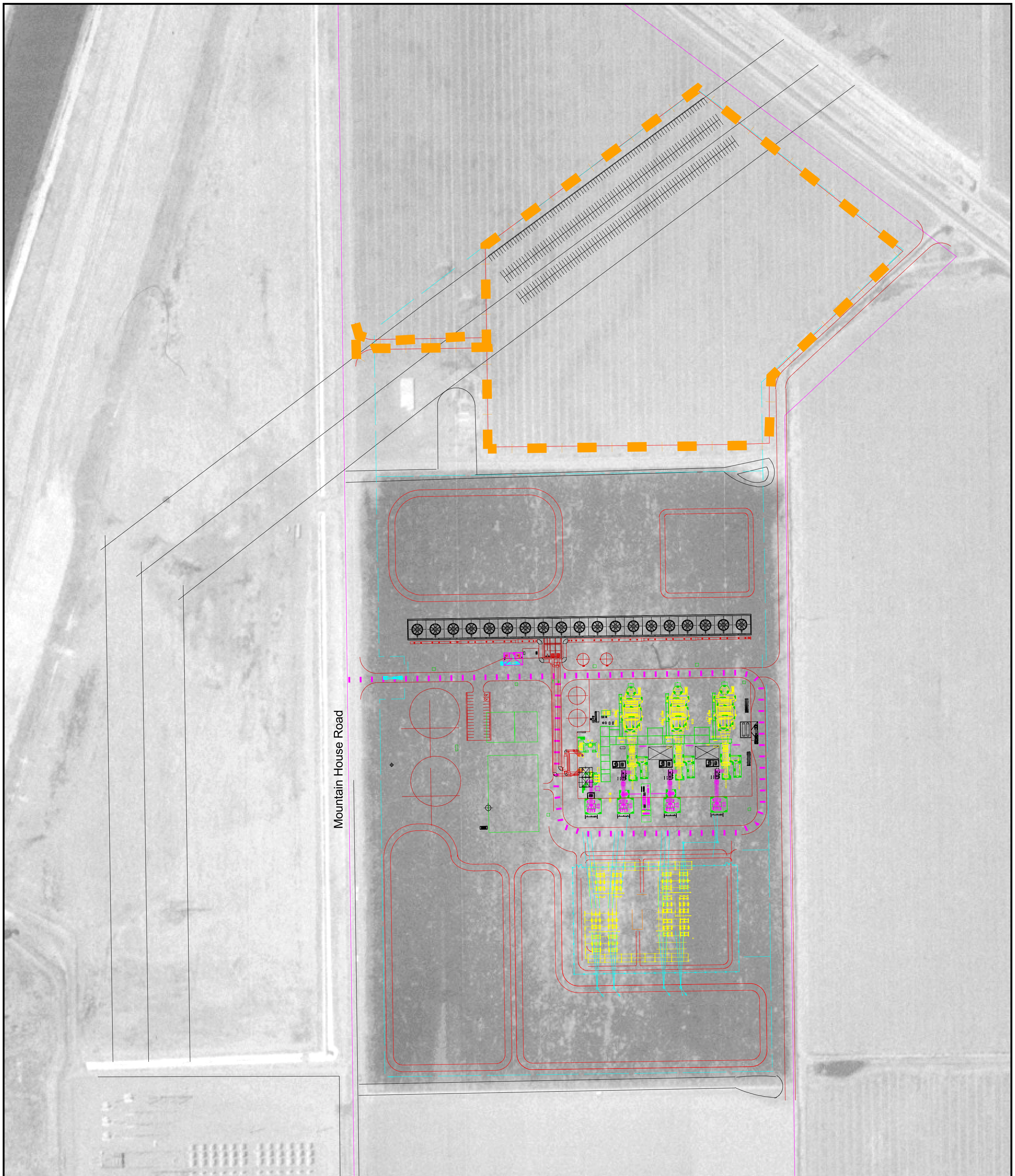

LEGEND

ACCESS ROAD

LAYDOWN AREA

N

200 0 200 Feet

SCALE IS APPROXIMATE

FIGURE 2.2-3
EAEC ACCESS ROAD AND LAYDOWN AREA

APPLICATION FOR CERTIFICATION
FOR EAST ALTAMONT ENERGY CENTER

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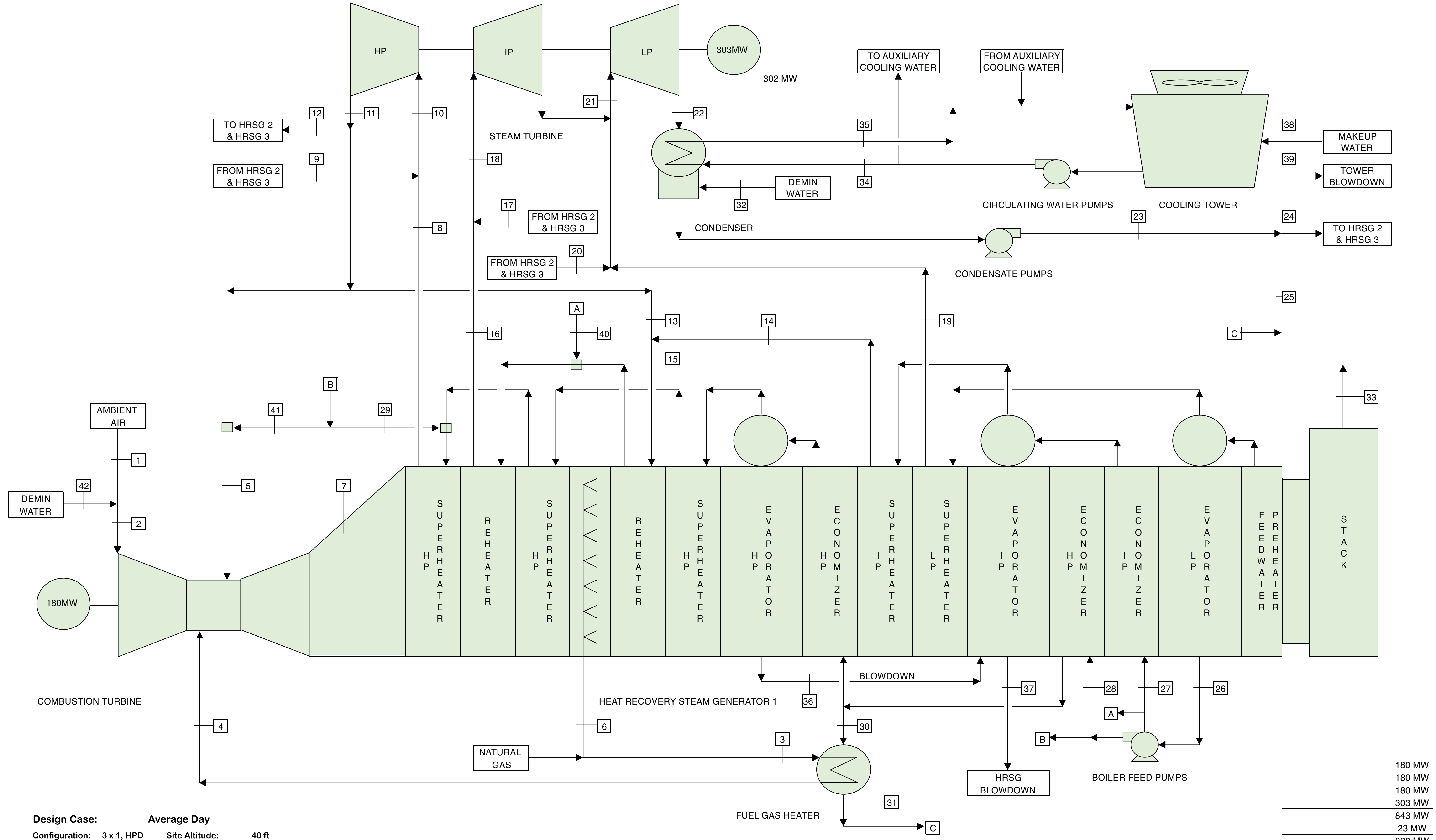

Design Case: **Average Day**

Configuration: 3 x 1, HPD Site Altitude: 40 ft
Dry Bulb Temp.: 61deg F Wet Bulb Temp: 51 deg. F
Fog: No
Power Aug.: No
Duct Firing: No

Source: CALPINE, Thomas M. Laronge, Inc., 2001

3250_08 (3/26/01)

FIGURE 2.2-4a
PLANT HEAT AND MASS BALANCE DIAGRAM-AVERAGE DAY
APPLICATION FOR CERTIFICATION
FOR EAST ALTAMONT ENERGY CENTER
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Stream No.	Units	1	2	3	4	5	6	7	8
Mass Flow	lb/hr	3,473,419	3,473,419	76,436	76,436	0	0	3,549,855	455,328
Temperature	°F	61	61	60	330	n/a	n/a	1,166	1,052
Pressure	psia	14.68	14.54	425	415	n/a	n/a	15.19	1,157
Stream No.	**Units**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**
Mass Flow	lb/hr	910,656	1,365,984	1,337,784	891,856	445,928	82,265	528,193	539,957
Temperature	°F	1,052	1,052	774	774	774	546	738	1,050
Pressure	psia	1,157	1,157	428	428	428	428	428	371
Stream No.	**Units**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
Mass Flow	lb/hr	1,079,914	1,691,871	39,818	79,636	1,767,525	1,767,525	1,767,525	1,178,350
Temperature	°F	1,050	1,050	505	505	544	82	82	82
Pressure	psia	371	371	52	52	51	0.55	125	125
Stream No.	**Units**	**25**	**26**	**27**	**28**	**29**	**30**	**31**	**32**
Mass Flow	lb/hr	589,175	584,742	78,487	462,577	28,136	35,385	35,385	0
Temperature	°F	82	365	367	372	372	461	137	n/a
Pressure	psia	125	100	470	1,395	1,395	440	430	n/a
Stream No.	**Units**	**33**	**34**	**35**	**36**	**37**	**38**	**39**	**40**
Mass Flow	lb/hr	3,549,855	126,100,000	126,100,000	0	0	1,647,840	254,900	15,542
Temperature	°F	185	64	77	n/a	n/a	70	77	367
Pressure	psia	14.68	35	25	n/a	n/a	20	25	470
Stream No.	**Units**	**41**							
Mass Flow	lb/hr	0							
Temperature	°F	n/a							
Pressure	psia	n/a							

Source: CALPINE, Thomas M. Laronge, Inc., 2001

3250_08 (3/26/01)

FIGURE 2.2-4b
HEAT AND MASS BALANCE DATA
DESIGN CASE: AVERAGE DAY
APPLICATION FOR CERTIFICATION
FOR EAST ALTAMONT ENERGY CENTER

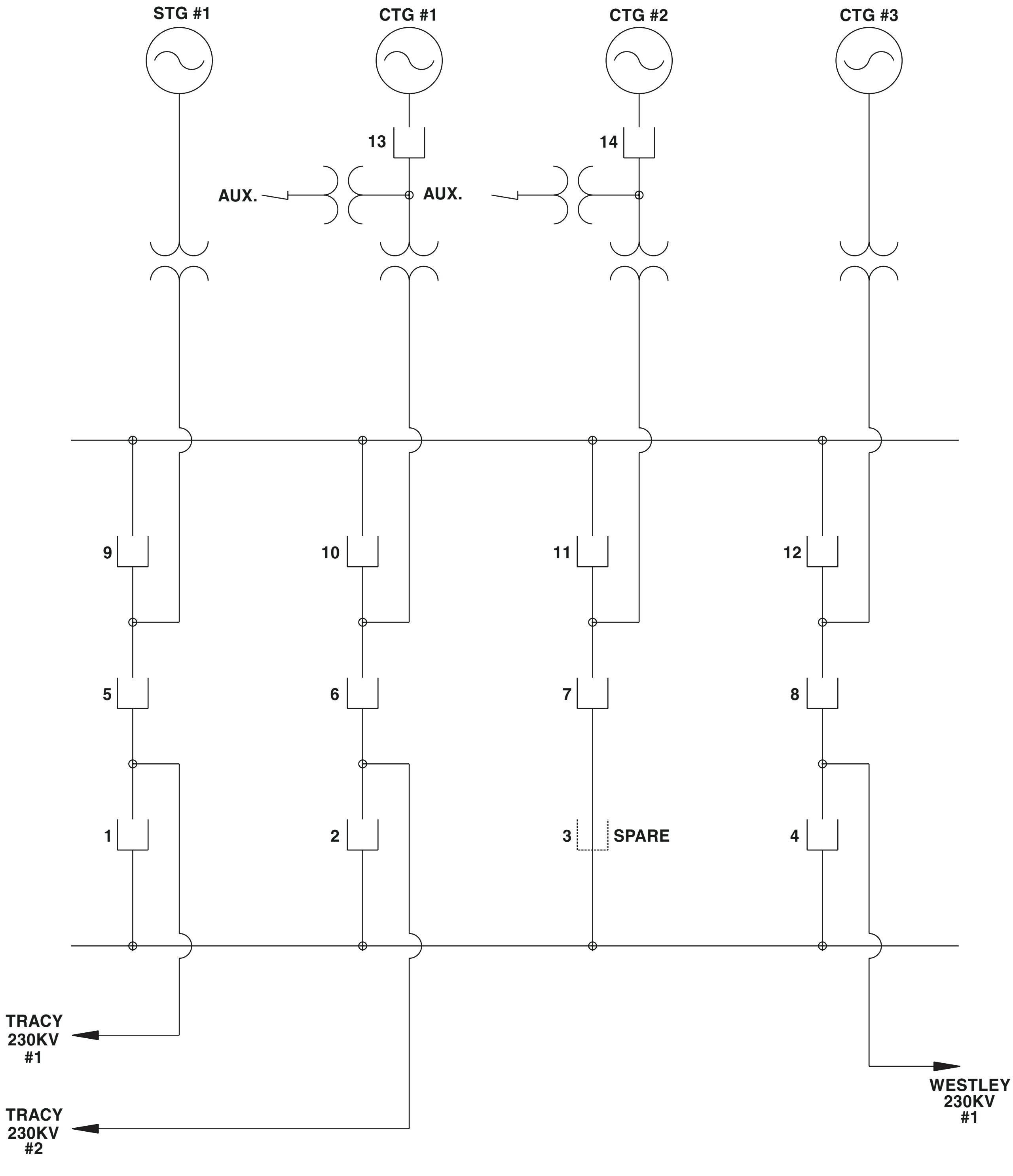
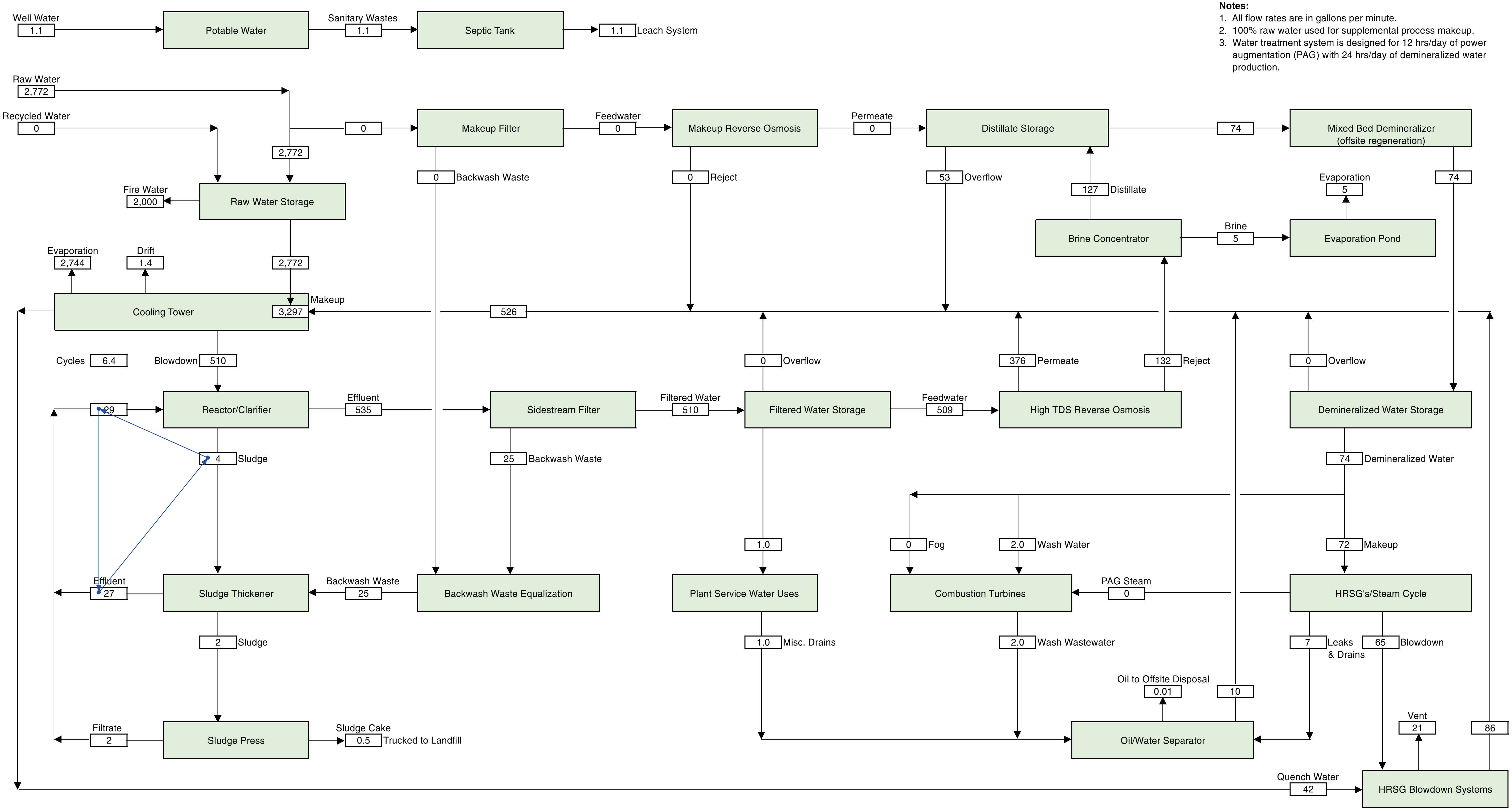


FIGURE 2.2-5
ONE-LINE SCHEMATIC OF THE PROPOSED 230 kV SWITCHYARD
EAST ALTAMONT ENERGY CENTER

CH2MHILL

3250_05 (2/12/01)

Notes:
1. All flow rates are in gallons per minute.
2. 100% raw water used for supplemental process makeup.
3. Water treatment system is designed for 12 hrs/day of power augmentation (PAG) with 24 hrs/day of demineralized water production.



Design Case: **Average Day - 100% Raw Water**

Configuration:	**3 x 1, HPD**	**Site Altitude:**	**40 ft**
Dry Bulb Temp.:	**61deg F**	**Wet Bulb Temp:**	**51 deg. F**
Fog:	**No**		
Power Aug.:	**No**		
Duct Firing:	**No**		

Source: CALPINE, Thomas M. Laronge, Inc., 2001

3250_03 (3/26/01)

FIGURE 2.2-6a
PLANT WATER BALANCE
AVERAGE DAY-100% RAW WATER
APPLICATION FOR CERTIFICATION FOR EAST ALTAMONT ENERGY CENTER

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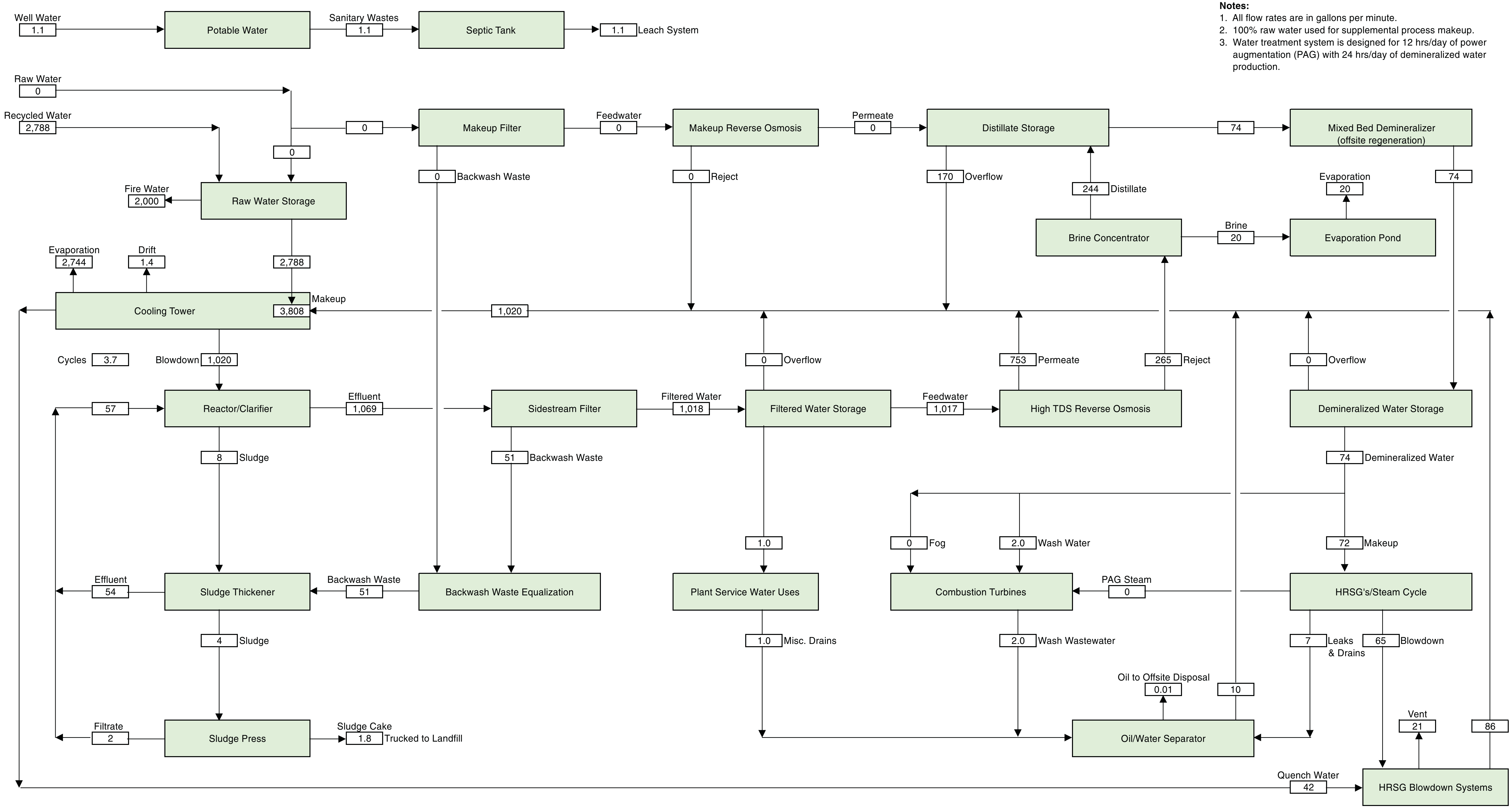
Notes:
1. All flow rates are in gallons per minute.
2. 100% raw water used for supplemental process makeup.
3. Water treatment system is designed for 12 hrs/day of power augmentation (PAG) with 24 hrs/day of demineralized water production.



Design Case: **Average Day - 100% Recycled Water**

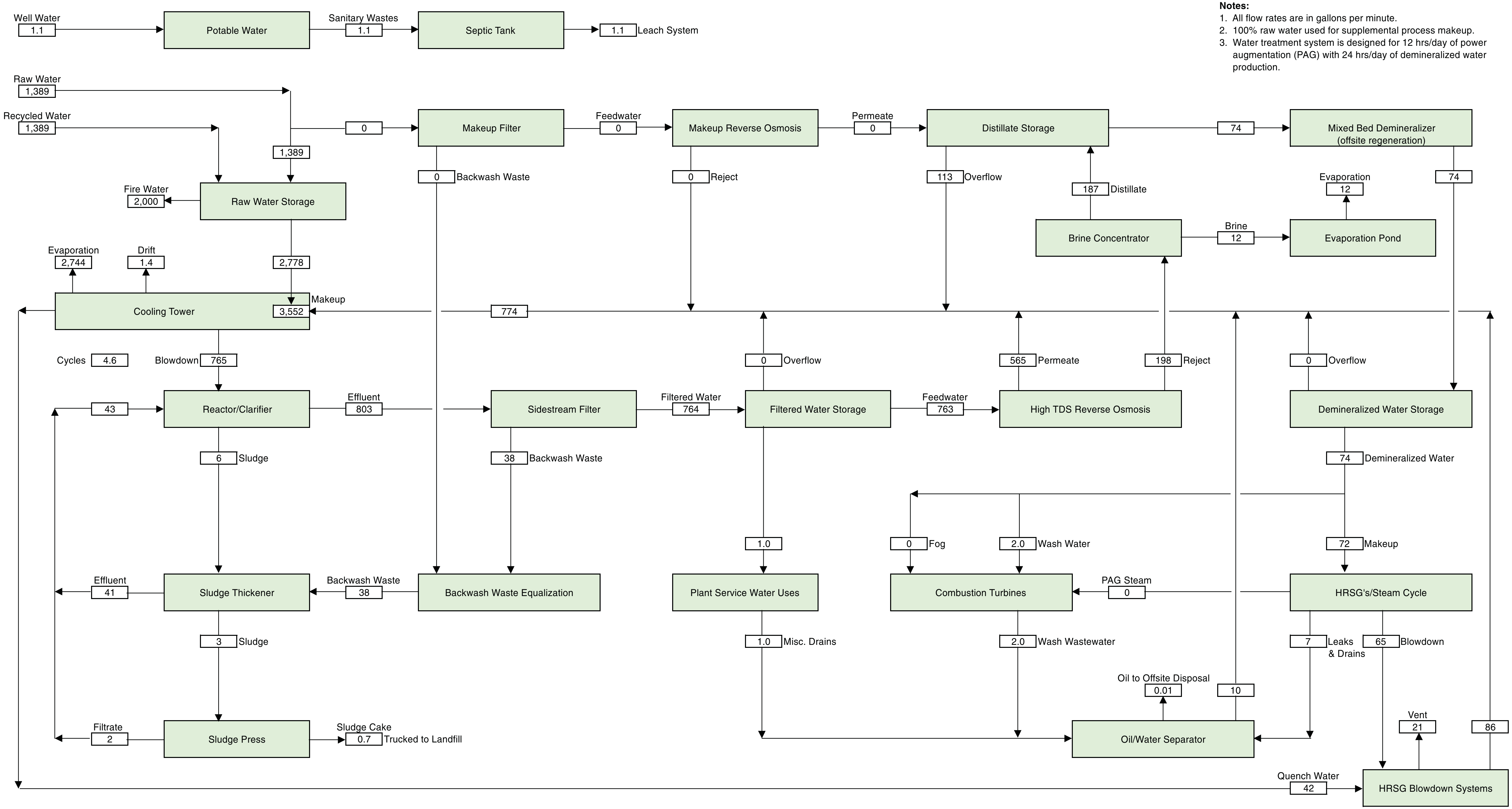
Configuration: 3 x 1, HPD **Site Altitude:** 40ft
Dry Bulb Temp.: 61 deg.F **Wet Bulb Temp.:** 51 deg.F
Fog: No
Power Aug.: No
Duct Firing: No

Source: CALPINE, Thomas M. Laronge, Inc., 2001

FIGURE 2.2-6b
PLANT WATER BALANCE
AVERAGE DAY-100% RECYCLED WATER
APPLICATION FOR CERTIFICATION FOR EAST ALTAMONT ENERGY CENTER
CH2MHILL

3250_03 (3/26/01)

Notes:
1. All flow rates are in gallons per minute.
2. 100% raw water used for supplemental process makeup.
3. Water treatment system is designed for 12 hrs/day of power augmentation (PAG) with 24 hrs/day of demineralized water production.



Design Case: **Average Day - 50% Recycled Water**

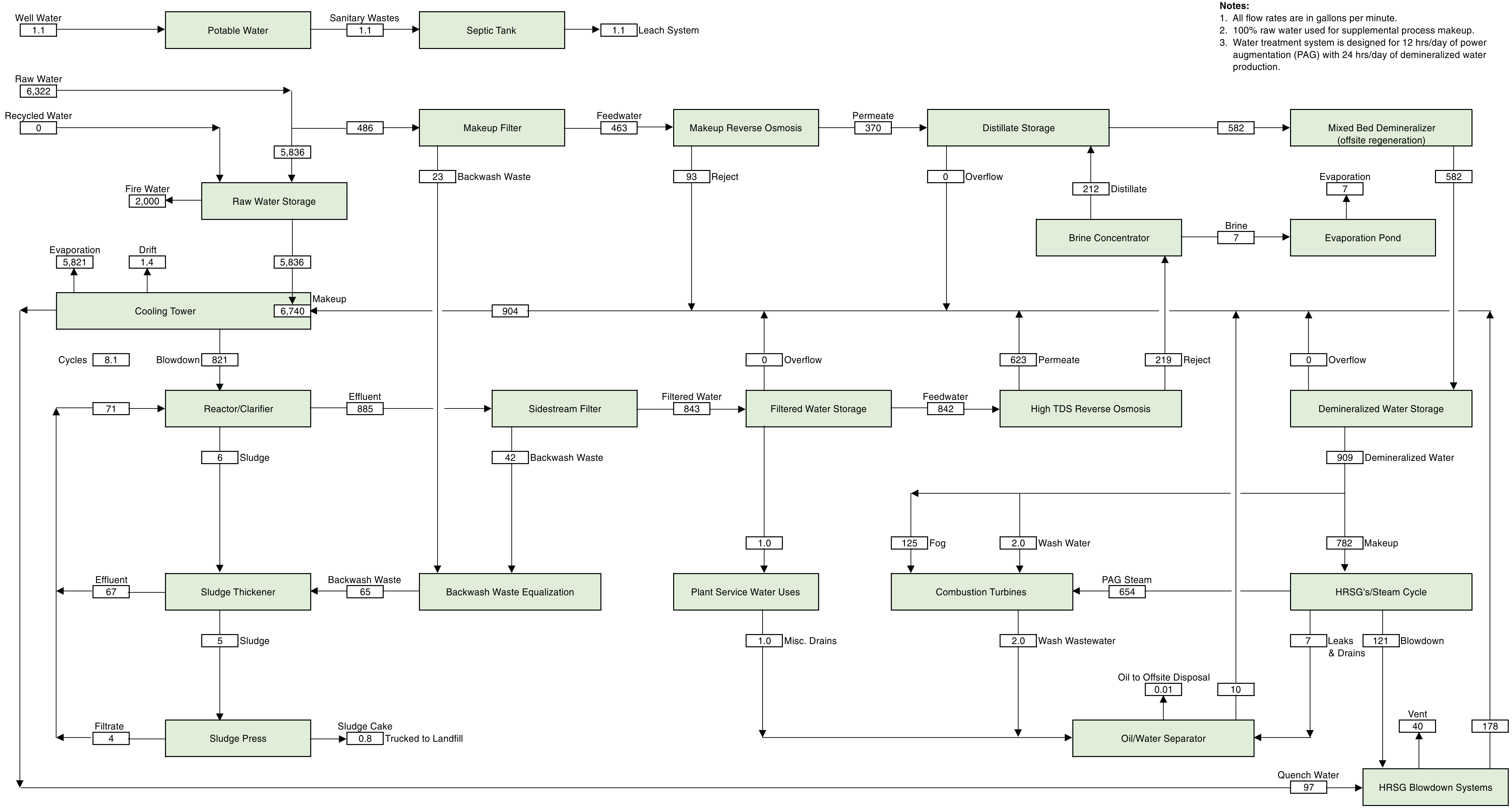
Configuration: 3 x 1, HPD **Site Altitude:** 40 ft
Dry Bulb Temp. 61 deg. F **Wet Bulb Temp.** 51 deg.F
Fog: No
Power Aug.: No
Duct Firing: No

Source: CALPINE, Thomas M. Laronge, Inc., 2001

3250_03 (3/26/01)

FIGURE 2.2-6c
PLANT WATER BALANCE
AVERAGE DAY-50% RECYCLED WATER
APPLICATION FOR CERTIFICATION FOR EAST ALTAMONT ENERGY CENTER
CH2MHILL

Notes:
1. All flow rates are in gallons per minute.
2. 100% raw water used for supplemental process makeup.
3. Water treatment system is designed for 12 hrs/day of power augmentation (PAG) with 24 hrs/day of demineralized water production.



Design Case: **Peak Day - 100% Raw Water**

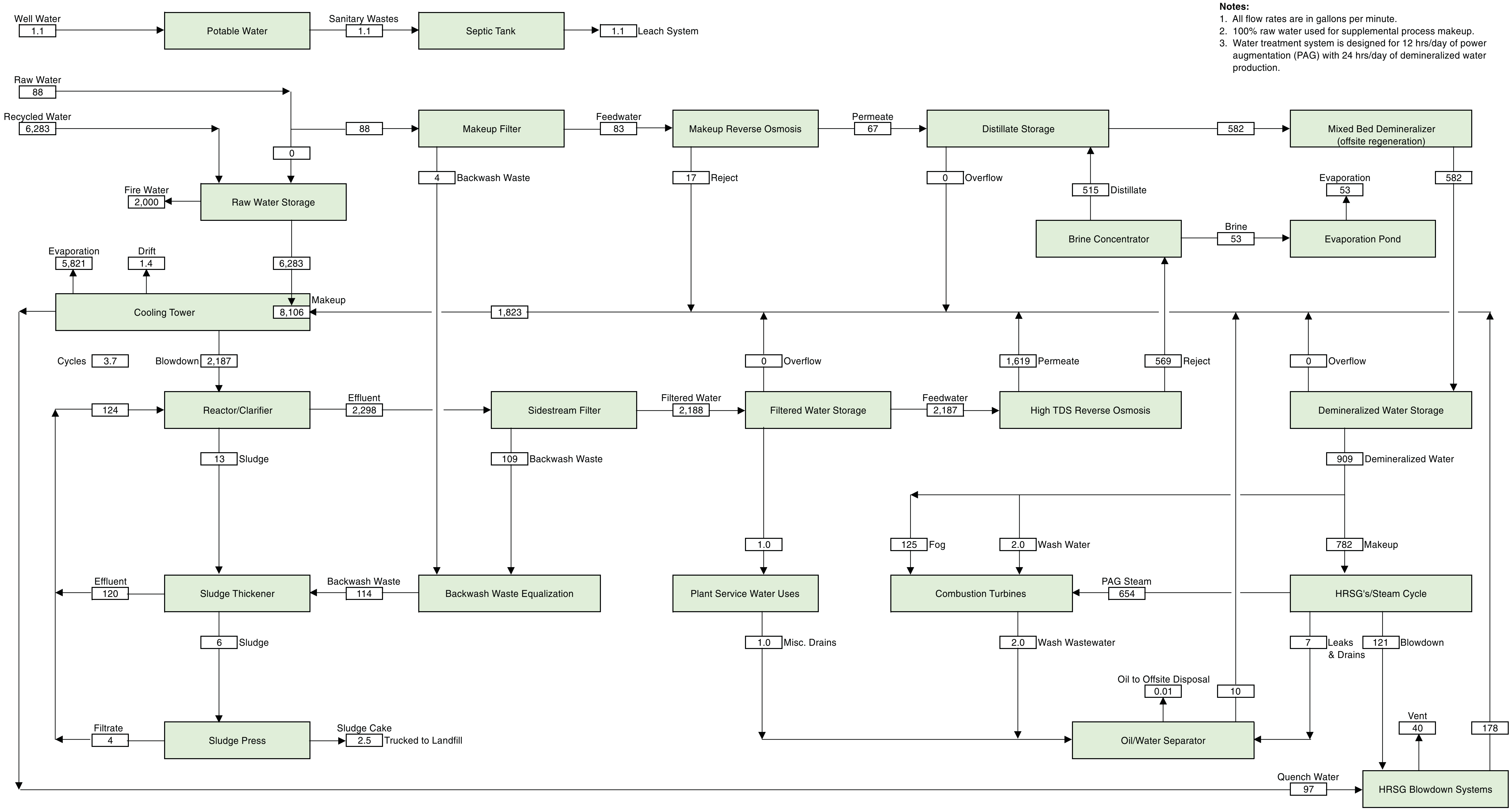
Configuration: 3 x 1, HPD **Site Altitude:** 40 ft
Dry Bulb Temp. 98 deg. F **Wet Bulb Temp.:** 70 deg.F
Fog: Yes
Power Aug.: Yes
Duct Firing: Yes

Source: CALPINE, Thomas M. Laronge, Inc., 2001

3250_03 (3/26/01)

FIGURE 2.2-6d
PLANT WATER BALANCE
PEAK DAY-100% RAW WATER
APPLICATION FOR CERTIFICATION FOR EAST ALTAMONT ENERGY CENTER
CH2MHILL

Notes:
1. All flow rates are in gallons per minute.
2. 100% raw water used for supplemental process makeup.
3. Water treatment system is designed for 12 hrs/day of power augmentation (PAG) with 24 hrs/day of demineralized water production.



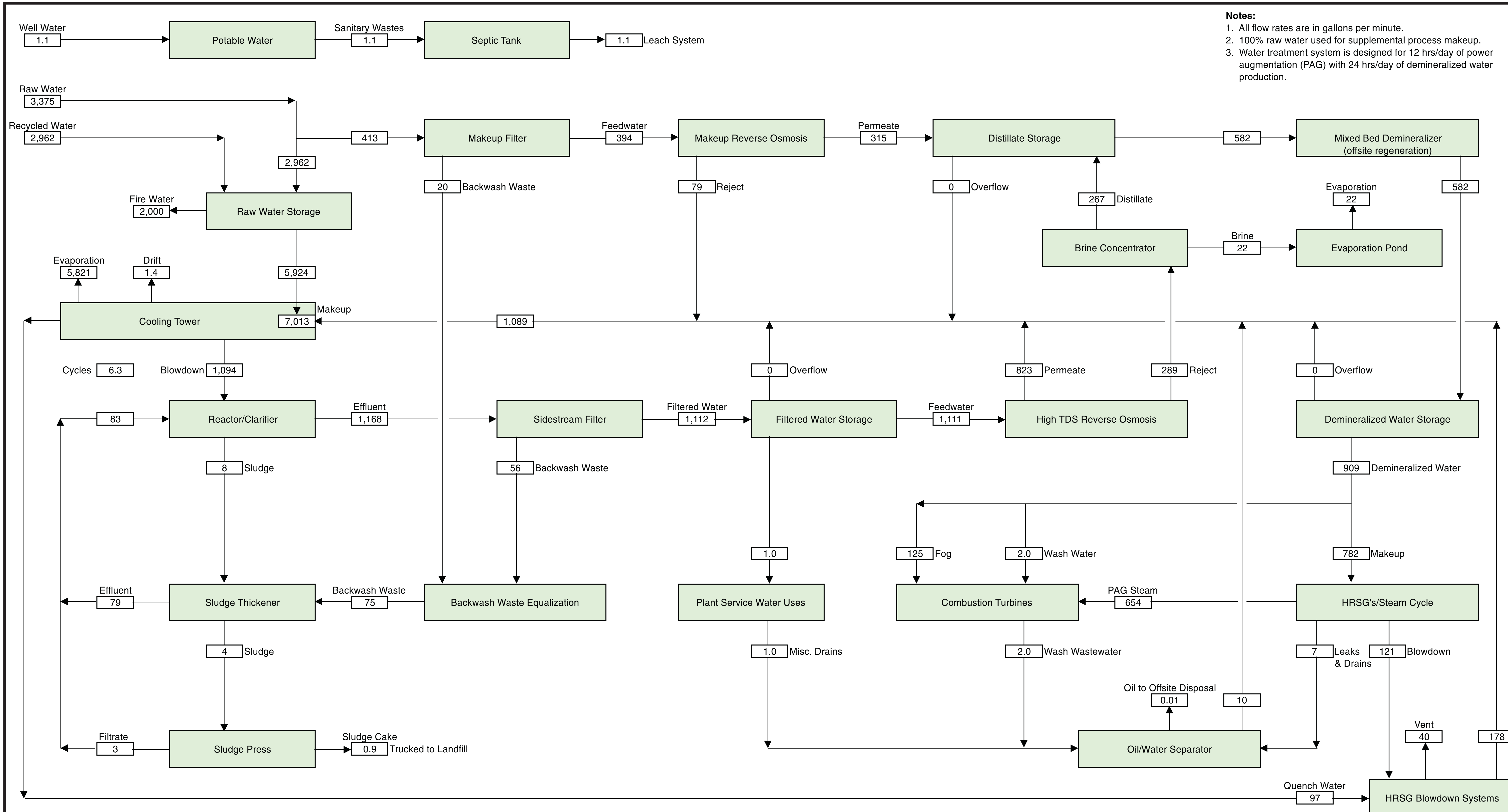
Design Case: **Peak Day - 100% Recycled Water**

Configuration: 3 x 1, HPD **Site Altitude:** 40 ft
Dry Bulb Temp. 98 deg. F **Wet Bulb Temp.:** 70 deg.F
Fog: Yes
Power Aug.: Yes
Duct Firing: Yes

Source: CALPINE, Thomas M. Laronge, Inc., 2001

3250_03 (3/26/01)

FIGURE 2.2-6e
PLANT WATER BALANCE
PEAK DAY-100% RECYCLED WATER
APPLICATION FOR CERTIFICATION FOR EAST ALTAMONT ENERGY CENTER
CH2MHILL



Design Case: **Peak Day - 50% Recycled Water**

Configuration:	**3 x 1, HPD**	**Site Altitude:**	**40 ft**
Dry Bulb Temp.	**98 deg. F**	**Wet Bulb Temp.:**	**70 deg.F**
Fog:	**Yes**		
Power Aug.:	**Yes**		
Duct Firing:	**Yes**		

Source: CALPINE, Thomas M. Laronge, Inc., 2001

3250_03 (3/26/01)

FIGURE 2.2-6f
PLANT WATER BALANCE
PEAK DAY-50% RECYCLED WATER

APPLICATION FOR CERTIFICATION FOR EAST ALTAMONT ENERGY CENTER

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3.0 Demand Conformance

The Commission is no longer required to determine if a proposed project conforms with an integrated assessment of need. Senate Bill 110 took effect on January 1, 2000 (Cal. Const. Art. 4, Section 8.) and states:

> "Before the California electricity industry was restructured the regulated cost recovery framework for generating facilities justified requiring the commission to determine the need for new generation, and site only generating facilities for which need was established. Now that generating facility owners are at risk to recover their investments, it is no longer appropriate to make this determination."

4.0 Facility Closure

Facility closure can be temporary or permanent. Temporary closure is defined as a shutdown for a period exceeding the time required for normal maintenance, including closure for overhaul or replacement of the combustion turbines. Causes for temporary closure include a disruption in the supply of natural gas or damage to the plant from earthquake, fire, storm, or other natural acts. Permanent closure is defined as a cessation in operations with no intent to restart operations owing to plant age, damage to the plant beyond repair, economic conditions, or other reasons. Section 4.1 discusses temporary facility closure; Section 4.2 discusses permanent facility closure.

4.1 Temporary Closure

For a temporary facility closure, where there is no release of hazardous materials, security of the facilities will be maintained on a 24-hour basis, and the CEC and other responsible agencies will be notified. Depending on the length of shutdown necessary, a contingency plan for the temporary cessation of operations will be implemented. The contingency plan will be conducted to ensure conformance with all applicable LORS and the protection of public health and safety and the environment. The plan, depending on the expected duration of the shutdown, may 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, as discussed in Section 8.13.

Where the temporary closure includes damage to the facility, and there is a release or threatened release of acutely hazardous materials into the environment, procedures will be followed as set forth in a Risk Management Plan (RMP) to be developed as described in Section 8.12. Procedures will include methods to control releases, notification of applicable authorities and the public, emergency response, and training for plant personnel in responding to and controlling releases of hazardous materials. Once the immediate problem is solved, and the acutely hazardous materials release is contained and cleaned up, temporary closure will proceed as described above for a closure where there is no release of hazardous materials.

4.2 Permanent Closure

The planned life of the generation facility is 30 years. However, if the generation facility were still economically viable, it could be operated longer. It is also possible that the facility could become economically noncompetitive earlier than 30 years, forcing early decommissioning. Whenever the facility is closed, the closure procedure will follow a plan that will be developed as described below.

The removal of the facility from service, or decommissioning, may range from "mothballing" to the removal of all equipment and appurtenant facilities, depending on conditions at the time. Because the conditions that would affect the decommissioning decision are largely unknown at this time, these conditions should be presented to the CEC and Alameda County when more information is available and the timing for decommissioning is more imminent.

To ensure that public health and safety and the environment are protected during decommissioning, a decommissioning plan will be submitted to the CEC for approval prior to decommissioning. The plan will discuss the following:

- Proposed decommissioning activities for the facility and all appurtenant facilities constructed as part of the facility
- Conformance of the proposed decommissioning activities to all applicable LORS and local/regional plans
- Activities necessary to restore the site if the plan requires removal of all equipment and appurtenant facilities
- Decommissioning alternatives other than complete restoration
- Associated costs of the proposed decommissioning and the source of funds to pay for the decommissioning

In general, the decommissioning plan for the facility will attempt to maximize the recycling of all facility components. Unused chemicals will be sold back to the suppliers or other purchasers or users. All equipment containing chemicals will be drained and shut down to ensure public health and safety and to protect the environment. All nonhazardous wastes will be collected and disposed of in appropriate landfills or waste collection facilities. All hazardous wastes will be disposed of according to all applicable LORS. The site will be secured 24 hours per day during the decommissioning activities.

5.0 Electric Transmission

5.1 Introduction

This section discusses the transmission interconnection between the EAEC and the existing electrical grid and the impacts the operation of the facility will have on the flow of electrical power in this region of California. Section 5.1 provides an introduction to this section. Section 5.2 discusses the existing electrical transmission system in the immediate vicinity of the EAEC. Section 5.3 discusses the proposed alternatives for electrical interconnection between the EAEC and the electrical grid and the preferred electrical transmission line route. The impacts of the electrical interconnection on the existing transmission grid are presented in Section 5.4. Section 5.5 focuses on potential nuisances (electrical, magnetic, audible noise, and corona effects) and safety of the interconnection. Section 5.6 provides a description of applicable LORS. Section 5.7 provides a list of references used in preparing this section.

The site for the proposed EAEC is located in the far northeastern corner of Alameda County, approximately 8 miles northwest of the city of Tracy, California. This location was selected, in part, for its ability to serve several energy markets due to its proximity to Western's Tracy substation, located adjacent to the pumping station for the Delta-Mendota Canal. Figure 5.1-1 (attached in a separate map pocket at the end of this section) shows the proposed location of EAEC in relation to the Tracy substation and the regional transmission facilities. As depicted on Figure 5.1-1, the site is immediately east across Mountain House Road from the Tracy substation. The proximity of these two facilities allows for a short transmission line alignment for the electrical interconnection.

PG&E, Western, and Modesto and Turlock Irrigation Districts (MID and TID) all own and operate high-voltage transmission lines in the vicinity of the EAEC. The Tracy substation serves as a connecting point between these electric utilities with lines owned by all three entering the substation. Those lines owned by PG&E are part of their San Joaquin Valley (Stockton Division) operating region. Those lines owned by Western are part of their Sierra Nevada operating region. This existing transmission network will deliver the power generated at the EAEC to the California electric grid.

The initial examination of the local transmission system concentrated on the anticipated EAEC power flows, capacity and location of existing transmission lines, availability of substation capacity, and physical distances involved with the anticipated electrical interconnection. The interconnection feasibility study included an analysis of looping existing 230-kV electrical transmission lines into the proposed EAEC and directly connecting the plant to the Tracy substation. System analyses concentrated on the existing 230-kV transmission network because of the nominal 1,100-MW design capacity for the EAEC and the proximity of existing 230-kV lines.

The proposed electrical transmission interconnection will connect the EAEC to the regional power grid by looping the existing Tracy-Westley 230-kV line jointly owned by MID and TID, approximately 2,200 feet north into EAEC switchyard. The Tracy-Westley 230-kV line runs east and west in the vicinity of the EAEC just south of Kelso Road. Figure 5.1-2 (all figures located at the back of the section) illustrates the location along the Tracy-Westley 230-kV line where it will be looped north into the EAEC switchyard. Since it is anticipated that Western will own and operate the EAEC switchyard and that the new switchyard will function as an extension of Western's 230-bus at the Tracy substation, it has been dubbed "Tracy B." In the rest of this section, the existing Tracy substation will be referred to as "Tracy A" and the new switchyard will be called "Tracy B." The interconnection will be a double-circuit 230-kV line resulting in the redesignation of the two segments (east and west of the interconnect point) of the Tracy-Westley line: Tracy A-Tracy B and Tracy B-Westley. The Tracy B-Westley portion of the line will be built in a double-circuit configuration but will be energized in a single-circuit configuration as a result of the physical and electrical layout within the Westley substation.

The proximity of Tracy A to the EAEC project allowed different conceptual interconnections to be considered with respect to their feasibility and anticipated impact on the existing transmission system and power flows. Primary consideration in the analysis was given to the ability of the existing transmission lines to carry the anticipated output of the EAEC. Additional aspects considered included environmental effects of building and maintaining the new interconnecting transmission line, ROW acquisition, engineering constraints, and costs. Alternative interconnection options were identified after analyses of these data and review of the PG&E and Western operating diagrams for their respective operating regions. From these alternatives the preferred transmission line alignment, interconnection configuration, and construction techniques were selected. Figure 5.1-3 (attached in a separate map pocket at the end of this section) is the Operating Diagram for PG&E's San Joaquin (Sheet 2) operating region. Figure 5.1-4 (also attached in a separate map pocket at the end of this section) is the Operating Diagram for Western's Sierra Nevada operating region. Further analysis, based on the Interconnection Data Sheet (attached as Appendix 5.1A), and discussion of the preferred interconnection, its alignment, and alternatives are found below in Sections 5.2 and 5.3.

5.2 Transmission Interconnection Engineering

This section discusses the existing transmission facilities in the vicinity of the EAEC project and other associated electrical facilities.

5.2.1 Existing Electrical Transmission Facilities

The proposed EAEC site is up to 55 acres in size and is located roughly 2,500 to 3,000 feet northeast of Western's Tracy A (230 yards to Tracy B). The substation is located in the northeastern reaches of Alameda County approximately 8 miles northwest of Tracy, California (Figure 5.1-1). This area of Alameda County is in the San Joaquin Valley, and the site is within 1,500 feet of the Delta-Mendota Canal. The proposed EAEC site lies adjacent to and immediately east of Mountain House Road. Kelso Road abuts to the south and Byron Bethany Road, to the north (Figure 5.1-2).

An inventory and an assessment of the transmission facilities in the immediate geographic area of the EAEC project were conducted. The regional transmission line assessment focused on the number of electrical transmission lines, rating of each line, existing loads, and the ability of the existing transmission grid to safely and reliably transport the summer peak output proposed to be generated at the EAEC.

Based on PG&E's Annual Transmission Assessment 2005 Heavy Summer Full-Loop Power Flow Base Case (2000 Series) Power Flow base-case provided by Western,[1] the portion of the San Joaquin Valley area that EAEC might readily impact[2] has 4,505 MW of peak load and 381 MW of generation.[3] The transmission system in the vicinity consists of 500-kV, 230-kV, 69-kV, and 60-kV transmission lines. These and other lines are shown on Figure 5.1-1. Typical 500-kV transmission line ratings for the area are between 2,122 and 2,590 megavolt amperes (MVA) with the Tracy-Tesla 500-kV line rated at 2,122 MVA and the Tracy to Olinda 500-kV line rated at 2,590 MVA. Local 230-kV ratings are typically 70 to 228 MVA. Table 5.2-1 lists the ratings and conductor types for selected lines in the vicinity of Tracy A.

TABLE 5.2-1
Capabilities of Lines in the Vicinity of Tracy A

From	To	Ckt. No.	Description	Volt.	Normal Rate (MVA)	Emerg Rate (MVA)	Conductor
Tracy	Tesla	1	Double-circuit	500	2122	3432	2-2300 AL Bundle
Tracy	Los Banos	1	Double-circuit	500	2122	3432	2-2300 AL Bundle
Tracy	Tesla	1	Double-circuit	230	333	485	954 ACSR
Tracy	Tesla	2	Double-circuit	230	333	485	954 ACSR
Tracy	Westley	1	Double-circuit (operated as 1 circuit)	230	650	650	954 ACSR
Tracy	Hurley	2	Single-circuit	230	318	318	1272 ACSR
Tracy	Unused	1	Double-circuit	230	[a]	[a]	[a]
Tracy	Unused	2	Double-circuit	230	[a]	[a]	[a]
Tracy	Lawrence Livermore	1	Double-circuit to Delta	230	318	318	795 ACSR
Tracy	Herdlyn	1	Single-circuit	69	76	89	[a]
Tracy	EBMUD	1	Single-circuit	69	[a]	[a]	[a]
Tracy	Los Vaqueros	1	Single-circuit	68	[a]	[a]	[a]
Tesla	Table Mountain	1	Single-circuit	500	2309	2309	2-2300 AL Bundle
Tesla	Vaca-Dixon	1	Single-circuit	500	2309	2309	2-2300 AL Bundle
Tesla	Contra Costa	1	Double-circuit	230	373	478	954 ACSR
Tesla	Contra Costa	2	Double-circuit	230	373	478	954 ACSR

[a] Data not available

To evaluate Tracy A, an approach called the "first contingency rated exit capability," or FCREC, was used. The evaluation started with the 2005 heavy summer peak case provided by Western and PG&E. This information was supplemented with connection information and line ratings from the San Joaquin Region (Sheet 2) Operating Diagram (Figure 5.1-3), taken from PG&E's Form 715 filing previously submitted to the Federal Energy Regulatory

[1] This is the case to be used for the system impact study as outlined in the Study Plan. The study is being conducted by Western, PG&E, MID, and TID with input from the ISO and other utilities in the region. At the time when this report was written, modifications to support the system impact study had not yet been completed. However, these changes are not expected to impact the load model.

[2] PG&E Mission, Stockton, and Stanisluas, MID, and TID zones used to approximate this area.

[3] Modeled as running in the power flow case.

Commission (FERC). From this database, an inventory of substation buses, generation, load, and line capacity was developed for Tracy A. This inventory, starting with the substation itself, served as a starting point for the FCREC method of evaluation. The objective of the evaluation was to find the rated exit capability for a bus or group of interconnected buses. To find the rated capability, the following three steps were undertaken:

1. Add the rating of all lines leaving, or exiting, the group;
2. Subtract the rating of all generators attached to any bus within the group; and
3. Add the rating of all loads attached to any bus within the group.

The sum of Steps 1, 2, and 3, above, yields a number called the "normal total rated exit capability," or NTREC, for the group. (The group of buses may also be called a "cut set.") The NTREC represents the maximum possible additional generation that can be accommodated at the cut-set location under the best of conditions. This is an optimistic number, but it can be refined easily using standard power-flow methodology.

The FCREC is the refined estimate of capacity. This number takes into account the most severe single contingency, or line outage. It provides a more realistic limit for added generation than does the NTREC found as a result of Steps 1, 2, and 3 above. To calculate the FCREC, or the final estimate of system capability, Steps 4 and 5 are applied to the process:

4. Find the line exiting the cut set that has the highest rating; and
5. Subtract the rating of the line identified in Step 4.

The FCREC gives the maximum possible export that might be expected without necessitating system improvements. Detailed estimates of the system impact will be determined in a System Impact Study sponsored by the Applicant and conducted by PG&E, Western, and MID/TID in accordance with the study plan developed for EAEC.

There is 5 MVA of load[4] at the 69-kV level at Tracy. Since there is no generation at Tracy A, the NTREC for the substation is, therefore, 9,331 MVA. The FCREC is 6,741 MVA, which is the maximum amount of generation that one might expect to add to Tracy A without necessitating system improvements. In addition to the capability of the line exits at Tracy A, there is substantial transformation capability there also. There is one 500/230-kV transformer rated at 850 MVA and two 230/69-kV transformers rated at 270 MVA each. Based on this abbreviated analysis, the addition of new generation facilities near Tracy A will result in minimal transmission impacts. Further, the plant is expected to provide badly needed voltage support to the Central Valley and to the critical substations (Tracy and Tesla) that feed the San Francisco Bay Area from this direction. A more accurate estimate of system impacts (both benefits and detriments) will be available once the system impact study is completed.

5.2.2 Proposed Transmission Interconnection System

The preferred interconnection between the proposed EAEC and Tracy A will consist of the following major facilities:

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[4] Above referenced Power Flow Case.

- Two new double-circuit overhead lines on two parallel tower structures extending approximately 2,200 feet from Tracy B to loop into the existing Tracy-Westley (MID/TID) 230-kV transmission line near the existing Tower No. 7 (Figure 5.1-2).
- New 230-kV breaker-and-a-half switchyard (Tracy B) adjacent (south side) to the EAEC power block.
- Modifications in Tracy A to uncouple the two 230-kV circuits of the MID/TID line between Tracy A and the point where the interconnection loops into Tracy B. A bay already exists so major bus work will not be required.

As a result of the EAEC's physical orientation on the proposed site, the transmission interconnection will exit the switchyard directly to the south for approximately 2,200 feet to the existing Tracy-Westley 230-kV transmission line. Figure 5.1-2 shows the location of the preferred electrical interconnection alignment (Route 1a) in relation to the proposed EAEC facility site, Tracy-Westley 230-kV transmission line, and Tracy A. It is anticipated that the interconnecting transmission will occupy a ROW approximately 380 feet wide.

5.2.2.1 East Altamont Energy Center 230-kV Switchyard Characteristics

The proposed Tracy B will consist of eleven 230-kV air-insulated circuit breakers. A breaker-and-a-half arrangement will be used in the switchyard to obtain a high level of service reliability. An electrical one-line diagram of the proposed Tracy B arrangement appears on Figure 5.2-1. The switchyard layout is shown on Figure 5.2-2.

The switchyard and all equipment are designed for a 63-kiloampere (kA) interrupting capacity. The main buses, as well as the bays, are designed for 3,000-A continuous current. As depicted on Figure 5.2-1, each generator will be provided with an independent tie to the switchyard. Tracy B will be connected to the existing transmission grid in a looped configuration and will, therefore, have two double-circuit transmission lines for connection to the 230-kV grid on two parallel tower structures. It is a current assumption of the system impact study that the double-circuit line to Westley will be operated in six-wire mode to prevent the need for modifications at the Westley substation. Three-line exits allow removal of a single circuit without limiting plant output. Redundant 18/13.8-kV power transformers connected to the step-up transformer side of the generator Breakers 13 and 14 will serve to start up the plant and provide power for all auxiliary loads within the EAEC facility. Power will be distributed via 15-kV metal-clad switchgear. Controls and protective relay systems for the 230-kV switchyard will be located in a control building separate from the generating facility. Auxiliary AC and DC power will be derived from auxiliary power transformers and a station battery system, respectively.

5.2.2.2 Overhead Line Characteristics

The Tracy-Westley (MID/TID) 230-kV line is built as a double-circuit line predominantly on single-pole steel structures. However, it is now operated as a single circuit. To improve reliability, the proposed interconnection modifications of the Tracy-Westley line will use an existing additional 230-kV bay at the Tracy bus to allow for the operation of the line as a double-circuit line between Tracy A and Tracy B. Due to present design characteristics at the Westley substation, the line will remain in its current operational configuration, i.e., constructed as a double-circuit but operated as a single-circuit, between Tracy B and the Westley substation.

The preferred interconnecting transmission line will be built overhead between Tracy B and the existing Tracy-Westley 230-kV transmission line. The preferred line will exit Tracy B and align due south for approximately 2,200 feet, where it will intersect the existing Tracy-Westley line. The two circuits will be approximately 260 feet apart. The east circuit (new Tracy B-Westley) will be a 230 kV single-circuit bifurcated with bundled conductors. The west two circuits (new Tracy B-Tracy A) will be 230-kV, also with bundled conductors. The recommended conductor for the preferred electrical interconnect transmission line is a "954 AAC bundle." This conductor type is presently being used in the existing Tracy-Westley 230-kV line.

The preferred overhead transmission line will use self-supporting tubular steel pole structures to hold the conductors. Figure 5.2-3 shows the typical tangent structure proposed for the line. This tower design is currently employed along the Tracy-Westley 230-kV line. The tangent structures will be located between the pull-off structures south of Tracy B and the intersection of the new line with the Tracy-Westley line. The same tower design will be used to carry the double-circuit side of the interconnection between Tracy B and Tracy A and the single-circuit side between Tracy B and the Westley substation. The structure design will allow for tangent angles up to approximately 2 degrees, ensuring flexibility in shifting tower locations perpendicular to the transmission line alignment to meet existing field conditions. Typically, the structures will be 110 feet tall (125 feet maximum) but may vary to match the existing structures along the Tracy-Westley line. The preferred line will exit Tracy B in a slack-span configuration to the pull-off structures. Figure 5.2-4 illustrates the design of the pull-off structures. There will be one such structure for each circuit (two for the jumpered circuit on the EAEC-Westley side). These structures are anticipated to be approximately 90 feet tall.

The single steel pole structure now standing in the Tracy-Westley line may need to be replaced to accommodate the new lateral forces created by the loop configuration where the line proceeds as a double-circuit from an east-west to a north-south orientation. Currently, the dimensions are approximate, and final placement will depend on the final choices for the design, layout, and existing conditions in the field. However, the preferred interconnection will intersect the existing 230-kV Tracy-Westley transmission line located on the south side of Kelso Road near Structure No. 7, south of Tracy B. Structure No. 7 of the existing line will require replacement with four new 90 degree angle dead-end structures, two where the Tracy B-Tracy A line exits the existing ROW and two where Tracy B-Westley line re-enters the existing ROW (Figure 5.1-2). Figure 5.2-5 shows a plan and profile design of the preferred single-pole 90 degree angle dead-end structures. These towers will be approximately 400 feet to the west of the present location of the existing Structure No. 7.

5.3 Proposed Transmission Interconnection Alternatives

This section describes alternatives to the preferred electrical transmission interconnection discussed in Section 5.2. Although several concepts for interconnection were generated in the initial development of the EAEC, almost all were rejected due to contractual issues, engineering feasibility, visual concerns, or cost. Only two of the initial options studied, Route 1a (the preferred alternative) and Route 1b, remain practical alternatives.

Section 5.3.1 presents Route 1b, a feasible alternative to the preferred route which is shown on Figure 5.1-2 and discussed throughout the environmental analysis. Section 5.3.2 discusses the additional initial options considered and rejected. Since these options no longer represent viable alternatives for EAEC, they are described as "potential alternatives" and are not discussed outside of this section.

5.3.1 Alternative 1b—Looping the Tracy-Westley 230-kV line (MID/TID) into Tracy B (Different ROW Alignment)

This alternative has the same electrical and physical elements as the preferred interconnection alternative, except the ROW would be aligned along the eastern property line. This alignment would place the ROW approximately 300 feet to the east of the alignment proposed in the preferred alternative, which requires the lines to exit Tracy B at a series of angles before aligning due south closer to the eastern property line. This alternative requires four new heavy-angle structures to handle the lateral forces at the point where the line turns south. It was thought that this alternative might have a lesser impact on farm operations since the ROW would be closer to the field edge. However, the four parallel tower structures, installed on a diagonal line, are harder to farm around than the two towers planned for the preferred alternative. In addition, these tower structures are closer to the facility's eastern neighbor and Mountain House new town. For all these reasons, this alternative was rejected.

5.3.2 Preliminary Transmission Interconnection Alternatives

One of the results of the transmission resource analysis was the development of several additional conceptual transmission interconnection options. Factors considered in the development and selection of the preferred transmission interconnection alternative were: (a) the ability of the existing transmission resources to carry the power generated by the EAEC, (b) environmental consequences, (c) ability to secure any additional ROW (if needed), and (d) engineering considerations and constraints. This location offers several interconnection options that might be feasible. However, one key objective of the project was to interconnect so that power could be sent into the California ISO grid, the TID and MID transmission systems, and the Western transmission system without incurring additional transmission wheeling charges. The preferred interconnection achieves this objective while the other alternatives face contractual problems.

Several potential alternatives were identified, analyzed, and discounted due to differences with the preferred transmission interconnection. These potential alternatives are presented below. Other potential alternatives, not discussed below, were also delineated, assessed, and rejected.

5.3.3 Potential Alternative 1 - Express Connection to Tracy A

This alternative transmission interconnection consists of the following major elements:

- A new 230-kV breaker-and-a-half switchyard adjacent to the EAEC

- A double-circuit overhead transmission line connecting Tracy B to the 230-kV bus at Tracy A
- Modifications to the 230-kV bus at Tracy A

Potential Alternative 1 would involve directly connecting the EAEC to the 230-kV bus at Tracy A with an overhead transmission line. This alternative would exit the generating facility site at the southwest corner of the project site, immediately adjacent to the EAEC electrical generators. The overhead line would be aligned directly west for approximately 1,300 feet into the East Altamont substation (Figure 5.1-1). Based on the lack of available bays in Tracy A, new bays would have to be constructed. Western would design the basic layout of any changes to the 230-kV bus.

Implementation of this alternative, among other considerations, would require no new ROW; however, there would be a new crossing of Mountain House Road. Due to the physical layout of Tracy A, this alternative would require crossing the 500-kV Tracy-Olinda transmission line within the boundaries of the substation.

This alternative was not selected because of the increased costs associated with adding new bays in the Tracy 230-kV switchyard and the increased costs and decreased reliability associated with crossing under the 500-kV structures to access the 230-kV bus.

Western also informed the Applicant that there was not adequate clearance between an intervening building and the 500-kV line overhead, and moving the building would be costly.

5.3.4 Potential Alternative 2 – Looping the Tracy-Hurley 230-kV Transmission Lines into Tracy B

Potential Alternative 2 involves looping into the existing Tracy-Hurley 230-kV transmission lines where they cross just north of the proposed EAEC site.

The major elements of this alternative are:

- Two new double-circuit overhead 230-kV interconnecting transmission lines looping into the two existing single-circuit Tracy-Hurley lines
- A 230-kV switchyard at the EAEC

This alternative would require that the EAEC physical configuration on the property be oriented with the switchyard north of the power block. This would allow for a shorter interconnection (approximately 500 feet) between the EAEC and the two Tracy-Hurley transmission lines. The interconnection line would exit Tracy B at the western end of the northern property line and run north to the Tracy-Hurley ROW (Figure 5.1-1).

This alternative was rejected because of the length of the Hurley lines, the capacity of the lines, and the current loading on the line. Should an outage of the new connections from Tracy B to Tracy A occur, the entire output of the units would be on the lines to Hurley. In certain instances this might cause an overload and, because these are long lines, remedies would be expensive.

5.3.5 Potential Alternative 3 – Looping One Circuit Each of the Double-Circuit Tracy-Tesla and Tracy to Wesley 230-kV Transmission Lines into the EAEC

Potential Alternative 3 involves looping one circuit of the Tracy-Westley 230-kV line and one circuit of the double-circuit Tracy-Tesla 230-kV transmission line into Tracy B (Figure 5.1-1). This alternative involves the same route alignment and preferred interconnection configuration, except it would continue farther west approximately 250 feet to the Tracy-Tesla 230-kV line ROW. This alternative was considered extensively as a means of achieving a physical connection to the three[5] transmission providers that will be served by EAEC. It utilized the existing double-circuit construction of the portion of the Tracy-Westley 230-kV line between the proposed plant site and Tracy A to eliminate one under-crossing of the 500-kV Tracy-Tesla and Tracy-Los Banos 500-kV lines.

The major elements of Alternative 3 are:

- Two new double-circuit overhead 230-kV interconnecting transmission lines, one to loop into the Tracy-Westley 230-kV line and the other to loop into the eastern circuit of the Tracy-Tesla 230-kV double-circuit line
- A 230-kV switchyard at the EAEC
- Additional work at Tracy A

This alternative was not selected because arrangements satisfactory to all parties were made to allow export of the power from the proposed site. Compared to the selected alternative, this alternative is less reliable because it adds a crossing of the Tracy-Los Banos and Tracy-Tesla 500-kV lines, and it requires additional transmission lines to be built off the project property.

5.3.6 Potential Alternative 4 - Interconnection at 500-kV: Interconnect to the Existing Tracy-Tesla, Tracy-Los Banos 500-kV Transmission Line or the Tracy-Olinda 500-kV Transmission Line

Potential Alternative 4 would join the Tracy-Tesla and Tracy-Los Banos 500-kV lines south of Tracy A (Figure 5.1-1). These two 500-kV lines are single-circuit lines that share common structures. Connecting to the Tracy-Olinda 500-kV line that exits Tracy A to the north was also considered. The major components of this alternative would be:

- A new double-circuit 500-kV interconnect transmission line
- A 500-kV switchyard
- 500-kV step-up transformers

[5] PG&E, Western, and MID/TID.

This potential alternative was rejected for the following reasons:

1. The 500-kV lines and switchyard are a part of the California-Oregon Tie Project and disruptions or changes to it would have wide impacts.
2. The local demand greatly exceeds the local generation, thus, the power from the proposed unit would likely flow through the 500/230-kV transformer, increasing losses and potentially overloading these units.
3. Construction of 500-kV facilities is more expensive than the proposed plan.

5.3.7 Potential Alternative 5 – Looping the Tracy-Westley 230-kV (MID/TID) into Tracy B (Different ROW Alignment)

Potential Alternative 5 has the same electrical and physical elements as the preferred interconnection alternative, except the ROW would be aligned along the western property line. This alignment will place the ROW approximately 1,000 to 1,200 feet to the west of the alignment proposed in the preferred alternative. Thus, it will run along the eastern edge of Mountain House Road (Figure 5.1-1). This alignment has the same anticipated impacts as the preferred configuration except for the alignment along Mountain House Road. Placing the interconnecting transmission line ROW along the road in this location will necessitate the removal of a residence and several associated outbuildings at the intersection of Mountain House and Kelso roads. As a result, this potential alternative was not considered further.

5.4 Interconnection System Impact Study

Interconnection studies include analysis of power flow, short circuit, transient stability, and other factors to assess the impacts of the preferred transmission interconnection on the integrated transmission grid. After contacting MID/TID, Western, and PG&E and following mutually agreed-upon procedures in accord with these providers' regulatory filings, the Applicant initiated a System Impact Study. A copy of the current study plan is included as Appendix 5.4A. The Interconnection Data sheet submitted by the Applicant is included in Appendix 5.1A. These documents are included for information and to record the chronological development, to the time of submission of this application, of the system impact studies.

Prior to selecting the EAEC site, the Applicant performed several studies to verify its suitability for development as a potential generation location. Based on the results of these studies, the Applicant believes that there will be minimal or no adverse transmission impacts. However, should there be any adverse impacts, the rich transmission assets at the site provide ample opportunities to mitigate them.

5.5 Transmission Line Safety and Nuisances

This section discusses safety and nuisance issues associated with the preferred electrical interconnection for the EAEC. Construction and operation of the preferred overhead transmission line will be undertaken in a manner to ensure the safety of the public as well as maintenance and ROW crews while supplying power with minimal electrical interference.

5.5.1 Electrical Clearances

Typical high-voltage overhead transmission lines are composed of bare conductors connected to supporting structures by means of porcelain, glass, or plastic insulators. The air surrounding the energized conductor acts as the insulating medium. Maintaining sufficient clearances, or air space, around the conductors to protect the public and utility workers is paramount to safe operation of the line. The safety clearance required around the conductors is determined by normal operating voltages, conductor temperatures, short-term abnormal voltages, wind-blown swinging conductors, contamination of the insulators, clearances for workers, and clearances for public safety. Minimum clearances are specified in the National Electric Safety Code (NESC). Electric utilities, state regulators, and local ordinances may specify additional (more restrictive) clearances. Typically, clearances are specified for:

- Distance between the energized conductors themselves
- Distance between the energized conductors and the supporting structure
- Distance between the energized conductors and other power or communication wires on the same supporting structure, or between other power or communication wires above or below the conductors
- Distance from the energized conductors to the ground and features such as roadways, railroads, driveways, parking lots, navigable waterways, airports, etc.
- Distance from the energized conductors to buildings and signs
- Distance from the energized conductors to other parallel powerlines

The preferred EAEC transmission interconnection will be designed to meet all national, state, and local code clearance requirements. Since the designer must take into consideration many different situations, the generalized dimensions provided in the figures of this section should be regarded as reference for the electric and magnetic field calculations only and not absolute. The minimum ground clearance for 230-kV transmission according to the NESC is 22.4 feet, based on the road-crossing minimum. The minimum ground clearance for 500-kV transmission lines according to the NESC is 28.4 feet, based on the road-crossing minimum. These are the design clearances for the maximum operating temperature of the line. Under normal conditions, the line operates well below maximum conductor temperature, and thus, the average clearance is much greater than the minimum. More in keeping with PG&E guidelines, we have chosen 30 feet as representative for making electrical effects calculations for the 230-kV lines and 40 feet as representative for making electrical effects calculations for the 500-kV line. The final design value will be consistent with General Order 95 (GO-95) of the California Public Utilities Commission (CPUC), and PG&E's guidelines for electric and magnetic field (EMF) reduction.

5.5.2 Electrical Effects

The electrical effects of high-voltage transmission lines fall into two broad categories: corona effects and field effects. Corona is the ionization of the air that occurs at the surface of the energized conductor and suspension hardware due to very high electric field strength at the surface of the metal during certain conditions. Corona may result in radio and television reception interference, audible noise, light, and production of ozone. This study includes audible noise considerations only. Field effects are the voltages and currents that may be induced in nearby conducting objects. The transmission line's 60-Hz electric and magnetic fields cause these effects.

5.5.2.1 Electric and Magnetic Fields

Operating powerlines, like the energized components of electrical motors, home wiring, lighting, and all other electrical appliances, produce electric and magnetic fields, commonly referred to as EMF. The EMF produced by the alternating current electrical power system in the United States has a frequency of 60 Hz, meaning that the intensity and orientation of the field changes 60 times per second.

The 60-Hz powerline fields are considered to be extremely low frequency. Other common frequencies are AM radio, which operates up to 1,600,000 Hz (1,600 kHz); television, 890,000,000 Hz (890 MHz); cellular telephones, 900,000,000 Hz (900 MHz); microwave ovens, 2,450,000,000 Hz (2.4 GHz); and X-rays, about 1 billion (10^{18}) hertz. Higher frequency fields have shorter wavelengths and greater energy in the field. Microwave wavelengths are a few inches long and have enough energy to cause heating in conducting objects. Higher frequencies, such as X-rays, have enough energy to cause ionization (breaking of molecular bonds). At the 60-Hz frequency associated with electric power transmission, the electric and magnetic fields have a wavelength of 3,100 miles and have very low energy that does not cause heating or ionization. The 60-Hz fields do not radiate, unlike radio-frequency fields.

Electric fields around transmission lines are produced by electrical charges on the energized conductor. Electric field strength is directly proportional to the line's voltage; that is, increased voltage produces a stronger electric field. The electric field is inversely proportional to the distance from the conductors, so that the electric field strength declines as the distance from the conductor increases. The strength of the electric field is measured in units of kilovolts per meter (kV/m). The electric field around a transmission line remains practically steady and is not affected by the common daily and seasonal fluctuations in usage of electricity by customers.

Magnetic fields around transmission lines are produced by the level of current flow, measured in terms of amperes, through the conductors. The magnetic field strength also is directly proportional to the current; that is, increased amperes produce a stronger magnetic field. The magnetic field is inversely proportional to the distance from the conductors. Like the electric field, the magnetic field strength declines as the distance from the conductor increases. Magnetic fields are expressed in units of milliGauss (mG). The amperes and, therefore, the magnetic field around a transmission line fluctuate daily and seasonally as the usage of electricity varies.

Considerable research has been conducted over the last 30 years on the possible biological effects and human health effects from EMF. This research has produced many studies that offer no uniform conclusions about whether long-term exposure to EMF is harmful or not. In the absence of conclusive or evocative evidence, some states, California in particular, have chosen not to specify maximum acceptable levels of EMF. Instead, these states mandate a program of prudent avoidance whereby EMF exposure to the public would be minimized by encouraging electric utilities to use low-cost techniques to reduce the levels of EMF.

Additional information on EMF is provided in Appendix 5.5A.

5.5.2.2 Audible Noise

Corona is a function of the voltage of the line, the diameter of the conductor, and the condition of the conductor and suspension hardware. The electric field is directly related to the line voltage and is the greatest at the surface of the conductor.

Large-diameter conductors have lower electric field gradients at the conductor surface and, hence, lower corona than smaller conductors. Also, irregularities (such as nicks and scrapes on the conductor surface) or sharp edges on suspension hardware concentrate the electric field at these locations and, thus, increase corona at these spots. Similarly, contamination on the conductor surface, such as dust or insects, can cause irregularities that are a source for corona. Raindrops, snow, fog, and condensation are also sources of irregularities. Corona typically becomes a design concern for transmission lines having voltages of 345 kV and above.

5.5.2.3 EMF and Audible Noise Assumptions

It is important that any discussion of EMF and audible noise include the assumptions used to calculate these values and to remember that EMF and audible noise in the vicinity of the powerlines vary with regard to line design, line loading, distance from the line, and other factors.

Both the electric field and audible noise depend upon line voltage, which remains nearly constant for a transmission line during normal operation. A worst-case voltage of 242 kV (230 kV + 5 percent) will be used in the EMF calculations for the 230-kV lines, and 525-kV (500 + 5 percent) will be used in the EMF calculations for the 500-kV line.

The magnetic field is proportional to line loading (amperes), which varies as generating facility generation is changed by the system operators to meet increases or decreases in demand for electrical power. Line-loading values assumed for the EMF studies were based on PG&E's Annual Transmission Assessment 2005 Heavy Summer Full-Loop Power Flow Base Case. The EAEC plant is assumed to be operating at 1,070 MW at a 0.85 power factor. At 230 kV, this power output is approximately 3,160 amps. Since the outgoing 230-kV transmission consists of a loop, the power will be carried away from the generating facility in two directions: toward the Tracy and Westley substations. A power flow study was conducted, as described in Section 5.5.2.3, EMF Calculations, to calculate how the power is expected to distribute over the outgoing circuits. The calculated power flow values are used in the EMF calculations and are tabulated in EMF Calculations.

Another important parameter for these studies is the phase arrangement of the lines, both existing and after the interconnection is made. The phasing (i.e., relative location of A, B, and C phases) on a double-circuit structure may offer some field cancellation, which results in reduced magnetic field values at the ROW edge. Studies have shown that cross-phasing double-circuit lines provides magnetic field reduction when both circuits are carrying power in the same direction. In cross-phasing, the circuit on one side of the structure is configured, for example, with Phases A, B, and C arranged from top to bottom, while the other circuit is configured C, B, A from top to bottom. In this particular study, the existing lines already incorporate cross-phasing.

The data used for the EMF and audible noise studies can be noted from the discussions contained in the following paragraphs and the figures.

Figure 5.5-1 illustrates the plan view of the transmission systems and locations of the three cross sections (A, B, and C) that were included in the EMF studies. The cross sections are viewed looking north. This plan view also shows that the interconnection will be made to the Tracy-Westley 230-kV circuit, which connects Western's Tracy A and MID/TID's Westley substation. The existing Tracy-Westley 230-kV circuit will be looped into Tracy B; that is, the existing circuit will be cut and brought into EAEC so that power can flow to the existing transmission system through either the Tracy or Westley substations. EMF values calculated for Cross Sections A and C represent the EMF levels without the EAEC and also for the EMF levels expected after the interconnection with the EAEC. Cross Section B, naturally, will have calculated values for the addition of the new tap lines only. Also, for purposes of calculating magnetic field, it is assumed in this study that the lowest clearance is 30 feet at mid-span for the 230-kV lines and 40 feet for the 500-kV line.

Figure 5.5-2 is Cross Section A, the 230-kV MID/TID transmission line corridor that runs north/south and is just southeast of the proposed EAEC site. This existing line consists of double-circuit structures but is operated as a single-circuit Tracy-Westley 230-kV line. The cross-phasing configuration, conductor and shield wire used, and dimensions assumed for the EMF studies are pictured. After the EAEC interconnection, Cross Section A will continue with the same phasing configuration for a reduced-EMF design. The MID/TID transmission line is rated for a nominal voltage of 230 kV.

Cross Section B, as seen on Figure 5.5-3, is the EAEC tap line corridor that runs north-south and is just east of the Tracy A site. The cross-phasing configuration, conductor and shield wire, and dimensions assumed for the EMF studies are pictured. This new line would consist of two double-circuit structures carrying the single-circuit EAEC-Westley 230-kV line and the double-circuit EAEC-Tracy 230-kV line.

Cross Section C is illustrated on Figure 5.5-4. This section consists of two existing PG&E transmission lines. The western line is a 230-kV double-circuit lattice tower structure. The eastern line is a 500-kV double-circuit lattice tower structure. The assumed phasing, conductor and shield wire, and dimensions used for the EMF studies are pictured.

EMF Calculations. EMFs were calculated at one meter above flat terrain using ENVIRO, a TL Workstation (TLW) program developed by the Electric Power Research Institute. Measurements for electric and magnetic fields at one meter above the ground surface is in accordance with the Institute of Electrical and Electronic Engineers (IEEE) standards. ENVIRO calculates the electric fields expressed as kV/m and the magnetic fields expressed in mG. The various inputs for the calculations include voltage, current load (amps), current angle (i.e., phasing), conductor type and spacing, number of subconductors, subconductor bundle symmetry, spatial coordinates of the conductors and shield wire, various labeling parameters, and other specifics. The field level is calculated perpendicular to the line and at mid-span where the overhead line sags closest to the ground (calculation point). The mid-span location, therefore, provides the maximum value for the field. Also using an ENVIRO mathematical model, audible noise is calculated at a 5-foot microphone height above flat terrain with information concerning rain, snow, and fog rates for daytime and nighttime hours as input. Audible noise is expressed in decibels. Graphs contained in this report and tables in Appendices 5.5B and 5.5C were produced by importing ENVIRO data into Microsoft Excel.

A power flow model was developed from a PG&E data set (Annual Transmission Assessment 2005 Heavy Summer Full-Loop Power Flow Base Case). Two scenarios were calculated for comparison:

1. Without the proposed EAEC operating
2. With the proposed EAEC generation of 1,100 MW added

The variations in the power flow are tabulated in Table 5.5-1.

TABLE 5.5-1
Normal Power Flows for EAEC Study Cases - Heavy Summer, 2005

		Without EAEC		With EAEC at 1070 MW		
	Line	**MVA**	**Current (Amps)**	**MVA**	**Current (Amps)**	**Percent change**
500 kV	Tracy A-Maxwell	1799	-1965[a]	1781	-1951[a]	-1.0
	Tracy A-Tesla	775	847	865	948	11.6
	Tracy A-Los Banos	234	256	510	559	117.9
230 kV	Tracy A-Tracy B #1 (Tracy-Westley)	266	643	217	-529[a]	-18.4
	Tracy A-Tracy B #2 (Tracy-Westley)	266	643	217	-529[a]	-18.4
	Tracy B-Westley (Tracy-Westley)[b]	266	643	392	959	47.4
		266	643	392	959	47.4
	Tracy A-Tesla #1	33	80	176	428	433.3
	Tracy A-Tesla #2	33	80	176	428	433.3
	Tracy A-Hurley #1	196	473	215	524	9.7
	Tracy A-Hurley #2	200	483	220	536	10.0
	Tracy A-LLNL	75	181	84	205	12.0
69 kV	Tracy A-Herdlyn	32	258	32	261	0.0
	Tracy A-Modesto #1	5	41	5	41	0.0
	Tracy A-Modesto #2	5	41	5	41	0.0

[A]Negative values for current signify flows into Tracy A; positive values represent flows from Tracy A.
[b]Line flows are split for field calculations because the Tracy - Westley circuit has double-circuit structures but operates as a single-circuit.

Results of EMF and Audible Noise Calculations.

Electric Field and Audible Noise. Line voltage and arrangement of the phases determine the electric field. The proposed configuration for the interconnection does not change either the voltage or the phasing of the existing line to the west of the tap point (toward Tracy) or to the east of the tap point (toward Westley, Cross Section A). Likewise, the PG&E lines represented by Cross Section C will not have a change in voltage or phasing. Therefore, the electric field in these vicinities will remain the same. The analytical results of the electric field are shown in Appendix 5.5D. Graphical views are shown on Figures 5.5-5 through 5.5-7.

The highest levels of corona and, hence, audible noise will occur during inclement weather when the line conductors are wet. For these conditions, the conductor will produce a small amount of corona. However, no change in audible noise over the existing lines will occur since the conductor and voltages will remain the same as those of the existing system. For the proposed tap line, the hardware used to connect the conductors to the structures will be of low-corona design. Special care will be employed during stringing of the conductor to minimize nicks and scrapes to the conductor. These actions will ensure a low-corona design. The analytical results for the audible noise calculations are shown in Appendix 5.5C. Graphical views are shown on Figures 5.5-8 through 5.5-10.

The complete analytical results of the magnetic field calculations are provided in Appendix 5.5E and a graphical view is given on Figures 5.5-11 through 5.5-13. Table 5.5-2 summarizes calculated values for the magnetic field. The ± 190 feet from centerline coincides with the edge of ROW for Cross Section B and the ± 60 feet from the centerline coincides with the edge of ROW for Cross Section A. For each cross section the distance is given where the maximum field value was located.

TABLE 5.5-2
Magnetic Field Calculated Field at Mid-span Perpendicular to Transmission Centerline

	Distance from Transmission Centerline (feet)				
System at Peak Load	**-190**	**-60**	**Location of Maximum Value Given Below**	**+60**	**+190**
Location A	**West of Centerline**		**At Center Line**	**East of Centerline**	
Without EAEC Plant	1.2	20.1	91.4	20.1	1.2
With EAEC Plant	1.8	30.0	136.3	30.0	1.8
Location B	**West of Centerline**		**+130**	**East of Centerline**	
Without EAEC Plant	N/A	N/A	N/A	N/A	N/A
With EAEC Plant	16.5	11.3	136.5	21.4	30.0
Location C	**West of Centerline**		**+100**	**East of Centerline**	
Without EAEC Plant	4.4	13.3	87.9	57.7	15.2
With EAEC Plant	10.2	24.5	97.2	58.2	15.3

Transmission Line EMF Reduction. While the State of California does not set a statutory limit for electric and magnetic field levels, the CPUC, which regulates electric transmission lines, mandates EMF reduction as a practicable design criterion for new and upgraded electrical facilities. As a result of this mandate, the regulated electric utilities, including PG&E, have developed their own design guidelines to reduce EMF at each new facility. The CEC, which regulates transmission lines to the point of connection, requires independent power producers (IPP) to follow the existing guidelines that are in use by local electric utilities or transmission-system owners.

In keeping with the goal of EMF reduction, the interconnection of the EAEC will be designed and constructed using the principles outlined in the PG&E publication, “Transmission Line EMF Guidelines.” These guidelines explicitly incorporate the directives of the CPUC by developing design procedures compliant with Decision 93-11-013 and General Orders 95, 128, and 131-D. That is, when the towers, conductors, and ROWs are designed and routed according to the PG&E guidelines, the transmission line is consistent with the CPUC mandate.

From page 12 of the PG&E guidelines, the primary techniques for reducing EMF anywhere along the line are to:

1. Increase the distance between conductors and EMF sensors
2. Reduce the spacing between the line conductors
3. Minimize the current on the line
4. Optimize the configuration of the phases (A, B, C)

Anticipated EMF levels have been calculated for the EAEC interconnection as designed. The CEC requires actual measurements of pre-interconnection background EMF for comparison with measurements of post-interconnection EMF levels. If required, the pre- and post-interconnection verification measurements will be made consistent with IEEE guidelines and will provide sample readings of EMF at the edge of the ROW. Additional measurements will be made upon request for locations of particular concern.

Conclusion on EMF and Audible Noise. In conclusion, there is no change to the existing lines' electric field or audible noise levels as there is no change to the voltage or line configurations. There is a local increase, though, of magnetic field levels since there is an increase of current load. No changes to the existing lines are recommended as they already incorporate cross-phasing for reduced EMFs.

5.5.2.4 Induced Current and Voltages

A conducting object such as a vehicle or person in an electric field will have induced voltages and currents. The strength of the induced current will depend upon the electric field strength, the size and shape of the conducting object, and the object-to-ground resistance. Examples of measured induced currents in a 1 kV/m electric field are about 0.016 milliampers (mA) for a person, about 0.41 mA for a large school bus, and about 0.63 mA for a large trailer truck.

When a conducting object is isolated from the ground and a grounded person touches the object, a perceptible current or shock may occur as the current flows to ground. The amount of current depends upon the field strength, the size of the object, and the grounding resistance of the object and person. Shocks are classified as below perception, above perception, secondary, and primary. The mean perception level is 1.0 mA for a 180-pound man and 0.7 mA for a 120-pound woman. Secondary shocks cause no direct physiological harm, but may annoy a person and cause involuntary muscle contraction. The lower average secondary-shock level for an average-sized man is about 2 mA. Primary shocks can be harmful. Their lower level is described as the current at which 99.5 percent of subjects can still voluntarily "let go" of the shocking electrode. For the 180-pound man this is 9 mA; for the 120-pound woman, 6 mA; and for children, 5 mA. The NESC specifies 5 mA as the maximum allowable short-circuit current to ground from vehicles, trucks, and equipment near transmission lines.

The mitigation for hazardous and nuisance shocks is to ensure that metallic objects on or near the ROW are grounded and that sufficient clearances are provided at roadways and parking lots to keep electric fields at these locations sufficiently low to prevent vehicle short-circuit currents below 5 mA.

Magnetic fields can also induce voltages and currents in conducting objects. Typically, this requires a long metallic object, such as a wire fence or aboveground pipeline that is grounded at only one location. A person who closes an electrical loop by grounding the object at a different location will experience a shock similar to that described above for an ungrounded object. Mitigation for this is to ensure multiple grounds on fences or pipelines, especially those that are oriented parallel to the transmission line. This will be achieved by following local utility practice of grounding permanent metallic objects within transmission ROWs.

Where railroads are crossed or are parallel to the transmission line, coordination is required with the railroad company to ensure that the magnetically induced voltages and currents in the rails do not interfere with railroad signal and communications circuits, which often are transmitted through the rails.

The proposed 230-kV interconnection will be constructed in conformance with GO-95 and Title 8 CCR 2700 requirements. Therefore, hazardous shocks are unlikely to occur as a result of project construction or operation.

5.5.3 Aviation Safety

Federal Aviation Administration (FAA) Regulations, Part 77 establishes standards for determining obstructions in navigable airspace and sets forth requirements for notification of proposed construction. These regulations require FAA notification for any construction over 200 feet in height above ground level. Also, notification is required if the obstruction is more than specified heights and falls within any restricted airspace in the approach to airports. For airports with runways longer than 3,200 feet, the restricted space extends 20,000 feet (3.3 nautical miles) from the runway. For airports with runways 3,200 feet or less, the restricted space extends 10,000 feet (1.7 nautical miles). For heliports, the restricted space extends 5,000 feet (0.8 nautical mile).

There is only one airport within 20,000 feet (3.3 nautical miles) of the proposed EAEC site, Byron Airport approximately 14,800 feet (2.8 nautical miles) northeast of the site. The primary runway is over 3,200 feet in length. Although the project may need to notify the FAA due to other tall elements of the project, the height of the transmission towers (125 feet maximum) does not trigger review. As a result of their location and height in relation to the Byron Airport, the structures of the preferred electrical transmission interconnect will pose no deterrent to aviation safety as defined in the FAA regulations.

5.5.4 Fire Hazards

The 230-kV transmission interconnection will be designed, constructed, and maintained in accordance with GO-95, which establishes clearances from other man-made and natural structures as well as tree-trimming requirements to mitigate fire hazards. It is not anticipated that the ROW for the preferred interconnecting transmission line will have any trees or brush due to its alignment across Kelso Road and the agricultural field between Tracy B and Kelso Road (see Figure 5.5-1).

5.6 Applicable Laws, Ordinances, Regulations, and Standards

This section provides a list of applicable LORS that apply to the preferred transmission line, substations, and engineering. The following compilation of LORS is in response to Section (h), of Appendix B attached to Article 6, of Chapter 5, of Title 20 of the California Code of Regulations. Inclusion of these data is further outlined in the CEC's publication entitled *Rules of Practice and Procedure & Generating Facility Site Certification Regulations.*

5.6.1 Design and Construction

Table 5.6-1 lists the applicable LORS for the design and construction of the preferred transmission line and substations.

TABLE 5.6-1
Design and Construction Laws, Ordinances, and Standards Applicable to EAEC Electric Transmission

LORS	APPLICABILITY	AFC CONFORMANCE SECTION
General Order 95 (GO-95), CPUC, "Rules for Overhead Electric Line Construction"	CPUC rule covers required clearances, grounding techniques, maintenance, and inspection requirements.	Section 5.2.2.1 Section 5.2.2.2
Title 8 California Code of Regulations (CCR), Section 2700 et seq. "High Voltage Electrical Safety Orders"	Establishes essential requirements and minimum standards for installation, operation, and maintenance of electrical installation and equipment to provide practical safety and freedom from danger.	Section 5.2.2
General Order 128 (GO-128), CPUC, "Rules for Construction of Underground Electric Supply and Communications Systems"	Establishes requirements and minimum standards to be used for the station AC power and communications circuits.	Section 5.2.2.1
General Order 52 (GO-52), CPUC, "Construction and Operation of Power and Communication Lines"	Applies to the design of facilities to provide or mitigate inductive interference.	Section 5.2.2.2 Section 5.5.2.1 Section 5.5.2.2 Section 5.5.2.3 Section 5.5.2.4
ANSI/IEEE 693 "IEEE Recommended Practices for Seismic Design of Substations"	Provides recommended design and construction practices.	Section 5.2.2.1
IEEE 1119 "IEEE Guide for Fence Safety Clearances in Electric-Supply Stations"	Provides recommended clearance practices to protect persons outside the facility from electric shock.	Section 5.2.2 Section 5.5.1
IEEE 998 "Direct Lightning Stroke Shielding of Substations"	Provides recommendations to protect electrical system from direct lightning strokes.	Section 5.2.2.1
IEEE 980 "Containment of Oil Spills for Substations"	Provides recommendations to prevent release of fluids into the environment.	Section 5.2.2.1
Suggested Practices for Raptor Protection on Powerlines, April 1996	Provided guidelines to avoid raptor collision or electrocution.	

5.6.2 Electric and Magnetic Fields

The applicable LORS pertaining to electric and magnetic field interference are tabulated in Table 5.6-2.

TABLE 5.6-2
Electric and Magnetic Field Laws, Ordinances, and Standards Applicable to EAEC Electric Transmission

LORS	Applicability	AFC Reference
Decision 93-11-013 of the CPUC	CPUC position on EMF reduction.	Section 5.5.2 Section 5.5.2.3.3
General Order 131-D (GO-131), CPUC, Rules for Planning and Construction of Electric Generation, Line, and Substation Facilities in California	CPUC construction-application requirements, including requirements related to EMF reduction.	Section 5.2.2 Section 5.5.1 Section 5.5.2
Pacific Gas & Electric Company, "Transmission Line EMF Design Guidelines"	Large local electric utility's guidelines for EMF reduction through tower design, conductor configuration, circuit phasing, and load balancing. (In keeping with CPUC D.93-11-013 and GO-131)	Section 5.2.2.1 Section 5.5.2
ANSI/IEEE 644-1994 "Standard Procedures for Measurement of Power Frequency Electric and Magnetic Fields from AC Powerlines"	Standard procedure for measuring EMF from an electric line that is in service	Section 5.5.2

5.6.3 Hazardous Shock

Table 5.6-3 lists the LORS regarding hazardous shock protection for the project.

TABLE 5.6-3
Hazardous Shock Laws, Ordinances, and Standards Applicable to EAEC Electric Transmission

LORS	Applicability	AFC Reference
Title 8 CCR Section 2700 et seq. "High Voltage Electrical Safety Orders"	Establishes essential requirements and minimum standards for installation, operation, and maintenance of electrical equipment to provide practical safety and freedom from danger.	Section 5.2.2.1 Section 5.2.2.2 Section 5.5.1
ANSI/IEEE 80 "IEEE Guide for Safety in AC Substation Grounding"	Presents guidelines for ensuring safety through proper grounding of AC outdoor substations.	Section 5.2.2.1 Section 5.5.1
National Electrical Safety Code (NESC), ANSI C2, Section 9, Article 92, Paragraph E; Article 93, Paragraph C.	Covers grounding methods for electrical supply and communications facilities.	Section 5.2.2.1 Section 5.2.2.2 Section 5.5.2.1 Section 5.5.2.2

5.6.4 Communications Interference

The applicable LORS pertaining to communication interference are tabulated in Table 5.6-4.

TABLE 5.6-4
Communications Interference Laws, Ordinances, and Standards Applicable to EAEC Electric Transmission

LORS	Applicability	AFC Reference
Title 47 CFR Section 15.25, "Operating Requirements, Incidental Radiation"	Prohibits operations of any device emitting incidental radiation that causes interference to communications. The regulation also requires mitigation for any device that causes interference.	Section 5.2.2 Section 5.5.2.1 Section 5.5.2.2 Section 5.5.2.3.3 Section 5.5.2.4
General Order 52 (GO-52), CPUC	Covers all aspects of the construction, operation, and maintenance of power and communication lines and specifically applies to the prevention or mitigation of inductive interference.	Section 5.2.2 Section 5.2.2.1 Section 5.5.2.2 Section 5.5.2.4
CEC staff, Radio Interference and Television Interference (RI-TVI) Criteria (Kern River Cogeneration) Project 82-AFC-2, Final Decision, Compliance Plan 13-7	Prescribes the CEC's RI-TVI mitigation requirements, developed and adopted by the CEC in past siting cases.	Section 5.2.2.1 Section 5.2.2.2 Section 5.5.2.2

5.6.5 Aviation Safety

Table 5.6-5 lists the aviation safety LORS that may apply to the proposed construction and operation of the EAEC.

TABLE 5.6-5
Aviation Safety Laws, Ordinances, and Standards Applicable to EAEC Electric Transmission

LORS	Applicability	AFC Reference
Title 14 CFR Part 77 "Objects Affecting Navigable Airspace"	Describes the criteria used to determine whether a "Notice of Proposed Construction or Alteration" (NPCA, FAA Form 7460-1) is required for potential obstruction hazards.	Section 5.2.2 Section 5.5.3
FAA Advisory Circular No. 70/7460-1G, "Obstruction Marking and Lighting"	Describes the FAA standards for marking and lighting of obstructions as identified by Federal Aviation Regulations Part 77.	Section 5.2.2 Section 5.5.3
Public Utilities Code (PUC), Sections 21656-21660	Discusses the permit requirements for construction of possible obstructions in the vicinity of aircraft landing areas, in navigable airspace, and near the boundary of airports.	Section 5.2.2 Section 5.5.3

5.6.6 Fire Hazards

Table 5.6-6 tabulates the LORS governing fire hazard protection for the EAEC project.

TABLE 5.6-6
Fire Hazard Laws, Ordinances, and Standards Applicable to EAEC Electric Transmission

LORS	Applicability	AFC Reference
Title 14 CCR Sections 1250-1258, "Fire Prevention Standards for Electric Utilities"	Provides specific exemptions from electric pole and tower firebreak and electric conductor clearance standards, and specifies when and where standards apply.	Section 5.2.2.2 Section 5.5.4
ANSI/IEEE 80 "IEEE Guide for Safety in AC Substation Grounding"	Presents guidelines for ensuring safety through proper grounding of AC outdoor substations.	Section 5.2.2.1 Section 5.5.4
General Order 95 (GO-95), CPUC, "Rules for Overhead Electric Line Construction" Section 35	CPUC rule covers all aspects of design, construction, operation, and maintenance of electrical transmission line and fire safety (hazards).	Section 5.2.2 Section 5.5.4

5.6.7 Jurisdictional Agencies

Table 5.6-7 identifies national, state, and local agencies with jurisdiction to issue permits or approvals, conduct inspections, and/or enforce the above-referenced LORS. Table 5.6-7 also identifies the associated responsibilities of these agencies as they relate to the construction and operation of the East Altamont Energy Center. Because the EAEC is interconnecting to a federally owned utility (Western), an EIS will be required for the project, with Western as lead agency.

TABLE 5.6-7
Jurisdictional Agencies for EAEC Electric Transmission

Agency or Jurisdiction	Responsibility
CEC	Jurisdiction over new transmission lines associated with thermal generating facilities that are 50 MW or more. (PRC 25500)
CEC	Jurisdiction of lines out of a thermal generating facility to the interconnection point to the utility grid. (PRC 25107)
CEC	Jurisdiction over modifications of existing facilities that increase peak operating voltage or peak kilowatt capacity 25 percent. (PRC 25123)
CPUC	Regulates construction and operation of overhead transmission lines. (General Order No. 95) (those not regulated by the CEC)
CPUC	Regulates construction and operation of power and communications lines for the prevention of inductive interference. (General Order No. 52)
FAA	Establishes regulations for marking and lighting of obstructions in navigable airspace. (AC No. 70/7460-1G)
NEPA (EIS with Western)	Because the EAEC is interconnecting to a federally owned utility (Western), an EIS will be required for the project, with Western as lead agency.
Local Electrical Inspector	Jurisdiction over safety inspection of electrical installations that connect to the supply of electricity. (NFPA 70)
Western Systems Coordinating Council (WSCC)	Establishes power supply design criteria to improve reliability of the power system.
County of Alameda	Establishes and enforces zoning regulations for specific land uses. Issues variances in accordance with zoning ordinances.
	Issues and enforces certain ordinances and regulations concerning fire prevention.

5.7 References

Overhead Conductor Manual, Southwire.

PG&E Interconnection Handbook, PG&E, December 15, 1998.

Electrical and Biological Effects of Transmission Lines, A Review, U.S. Department of Energy, Bonneville Power Administration, Portland, Oregon, June 1989.

Transmission Line Reference Book, 115-138-kV Compact Line Design, Electric Power Research Institute, Palo Alto, California, 1978.

Transmission Line Reference Book, 345-kV and Above, Electric Power Research Institute, Palo Alto, California, 1975.

Corona and Field Effects of AC Overhead Transmission Lines, Information for Decision Makers, IEEE Power Engineering Society, July 1985.

PG&E Federal Energy Regulatory Commission (FERC) Form 715, 1998.

Western Federal Energy Regulatory Commission (FERC) Form 715, 1999.

Power flow cases used for the East Altamont Energy Center-DFS as supplied by PG&E.

California Independent System Operator, 1999 Summer Peak Power Flow Case.

Power Flow Case provided by PG&E.

California Public Service Commission, General Order 95-Rules for Overhead Electric Line Construction.

California Public Service Commission, General Order 128-Rules for Construction of Underground Electric Supply and Communications Systems.

California Public Service Commission, General Order 52-Construction and Operation of Power and Communication Lines

California Public Service Commission, General Order 131D-Rules for Planning and Construction of Electric Generation, Line, and Substation Facilities.

California Public Service Commission, Decision 93-11-013.

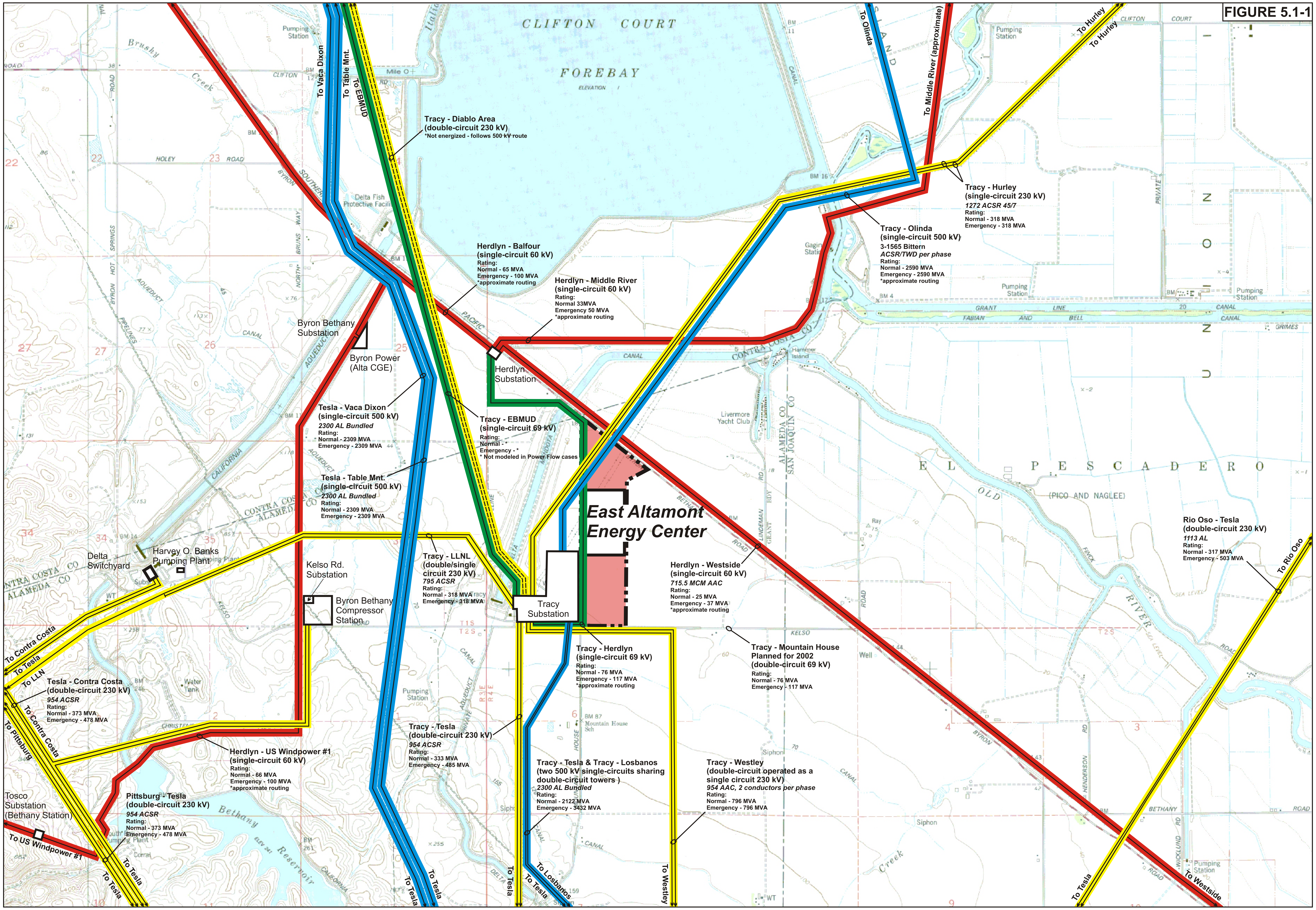
National Electrical Safety Code, ANSI C2.

United States of America, 47CFR15.25-Operating Requirements, Incidental Radiation.

United States of America, 15CFR77-Objects Affecting Navigable Airspace.

United States of America, 14CFR1250-1258-Fire Prevention Standards for Electric Utilities.

FIGURE 5.1-1



Existing 500 kV Transmission Line
Existing 230 kV Transmission Line
Existing 230 kV Transmission Line (not energized)
Existing 69 kV Transmission Line
Existing 60 kV Transmission Line

Scale: 1" = 2000'

0 1000 2000 3000 4000

FEET

California

Map Area

FIGURE 5.1-1

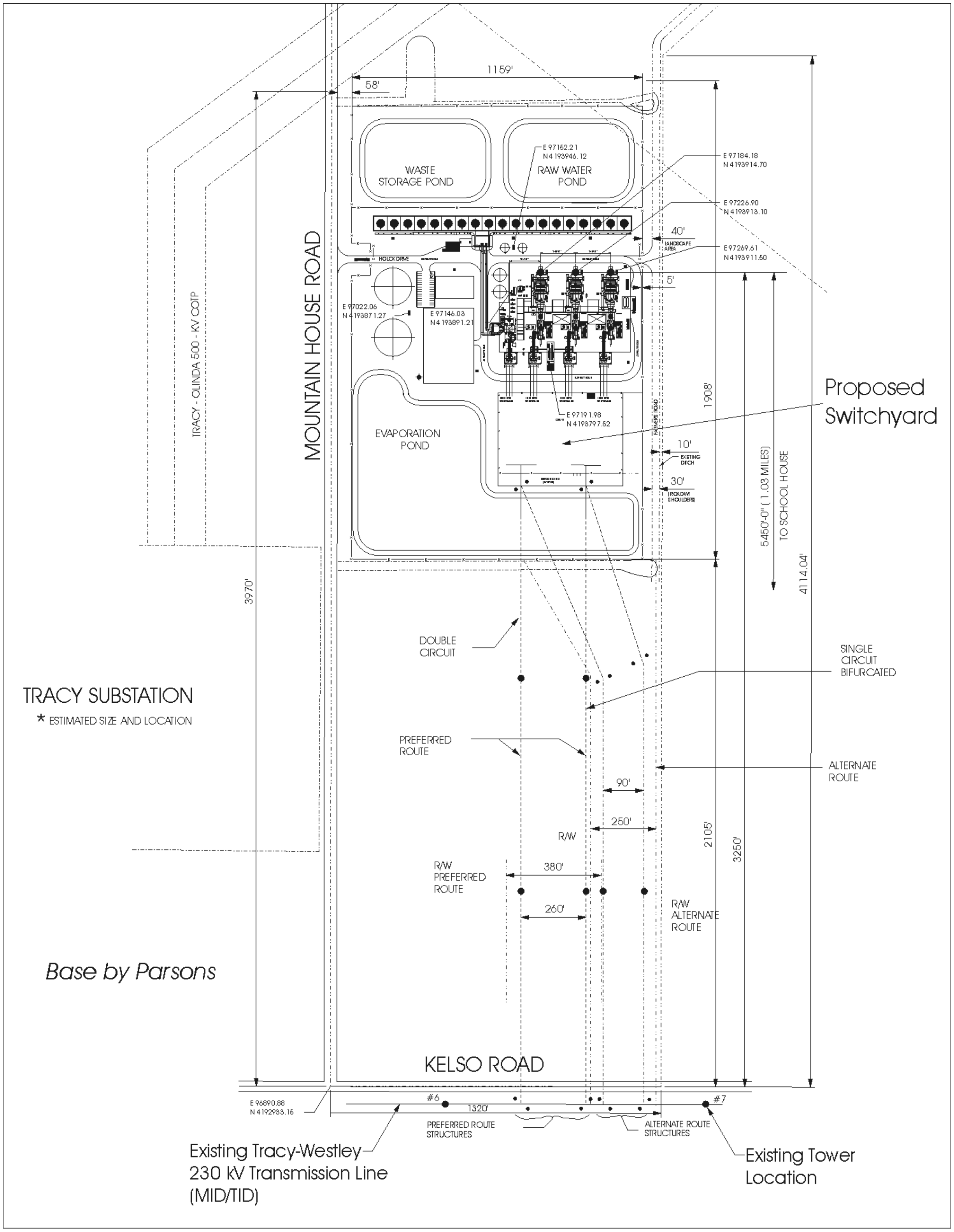
Transmission in the Vicinity of the Proposed East Altamont Energy Center

Calpine

January 8, 2001

Prepared By:
Commonwealth Associates Inc.
Jackson, Michigan
Engineers • Consultants • Construction Managers

Basemap: Sure!Maps Raster - USGS 7.5 Minute Topographic Quadrangle Maps.



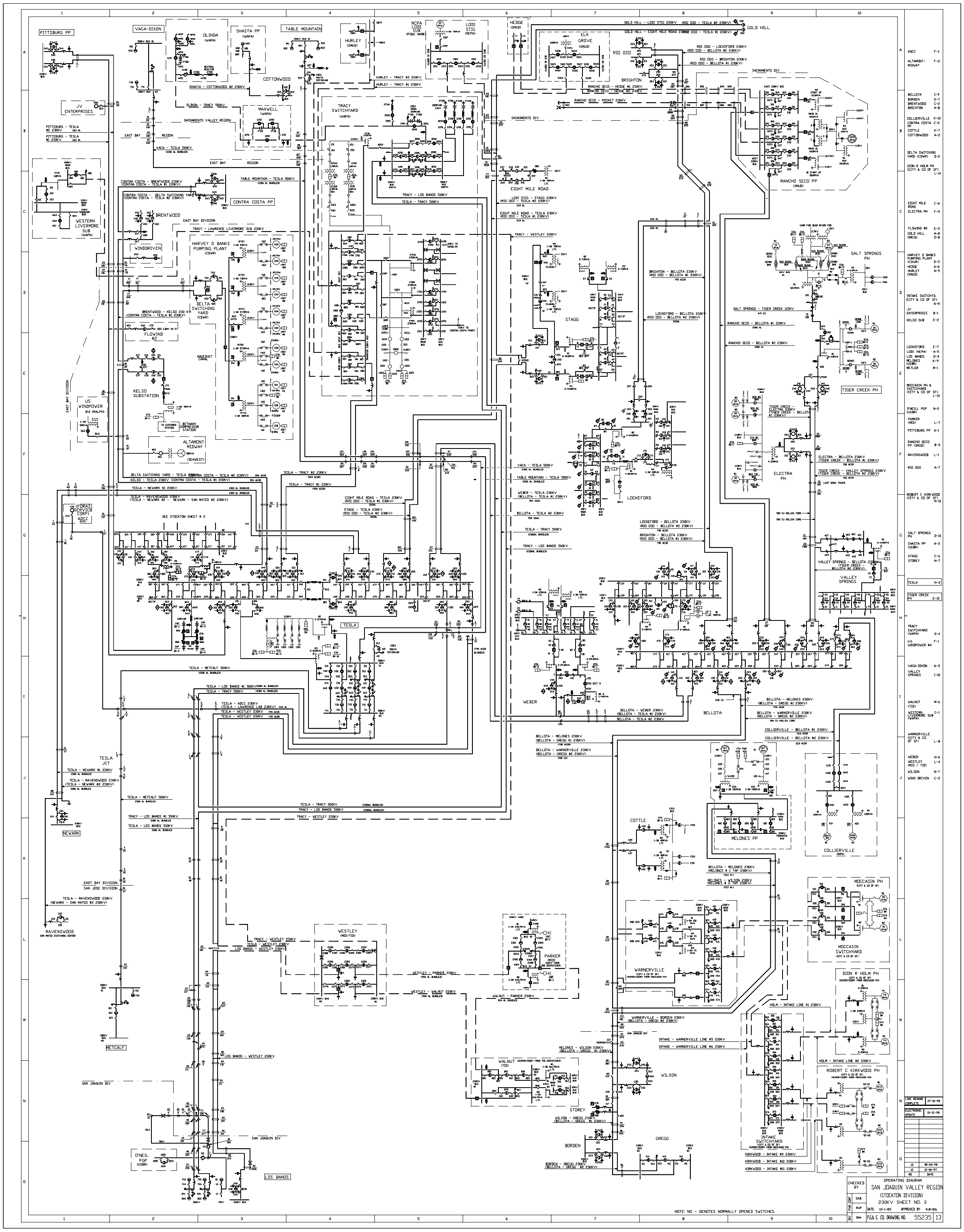
Conceptual R/W and Structure Placement

Figure 5.1-2

January 8, 2001

East Altamont Energy Center - Calpine Corporation

Prepared By: Commonwealth Associates Inc.
Jackson, Michigan
Engineers Consultants Construction Managers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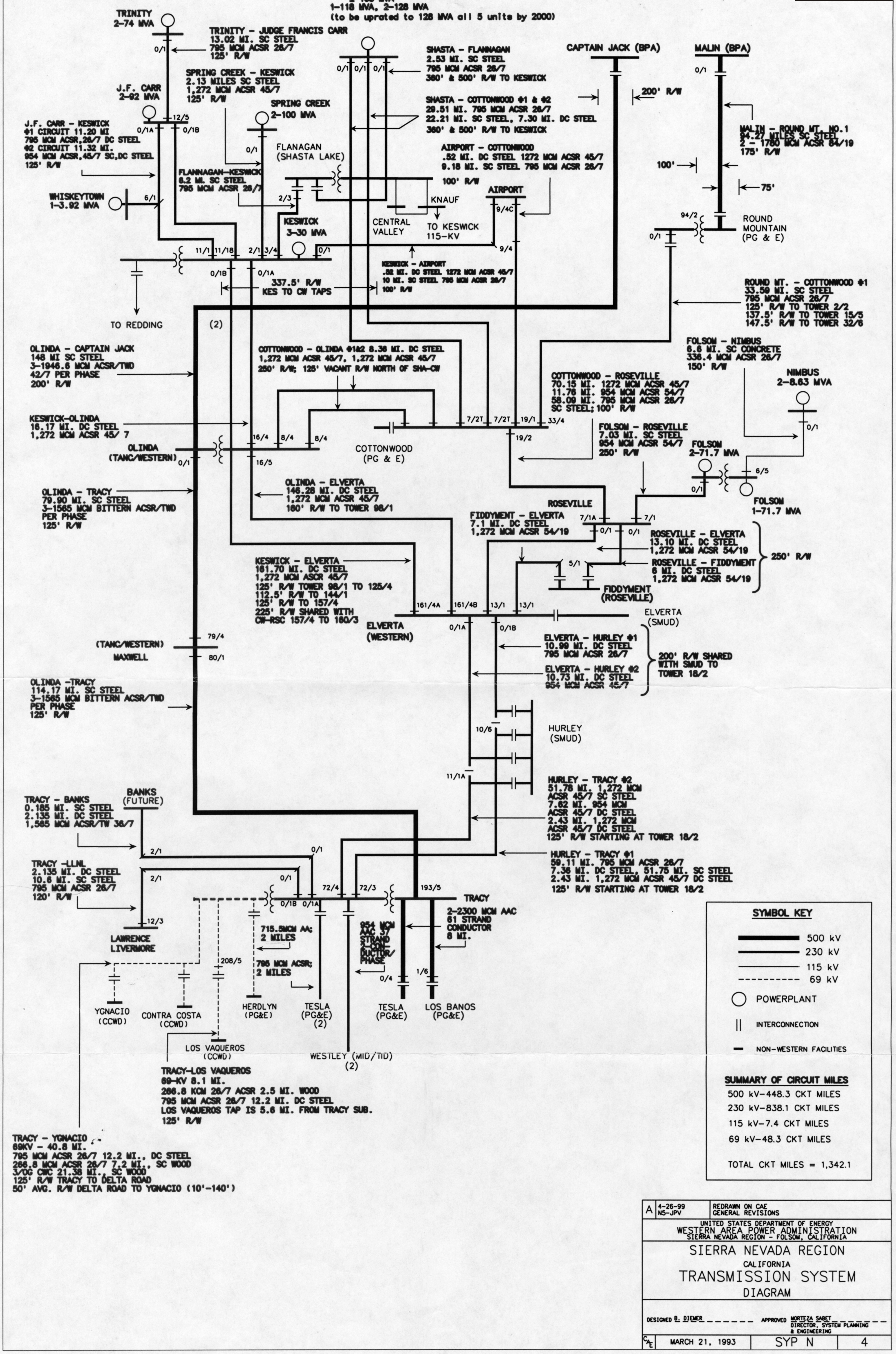
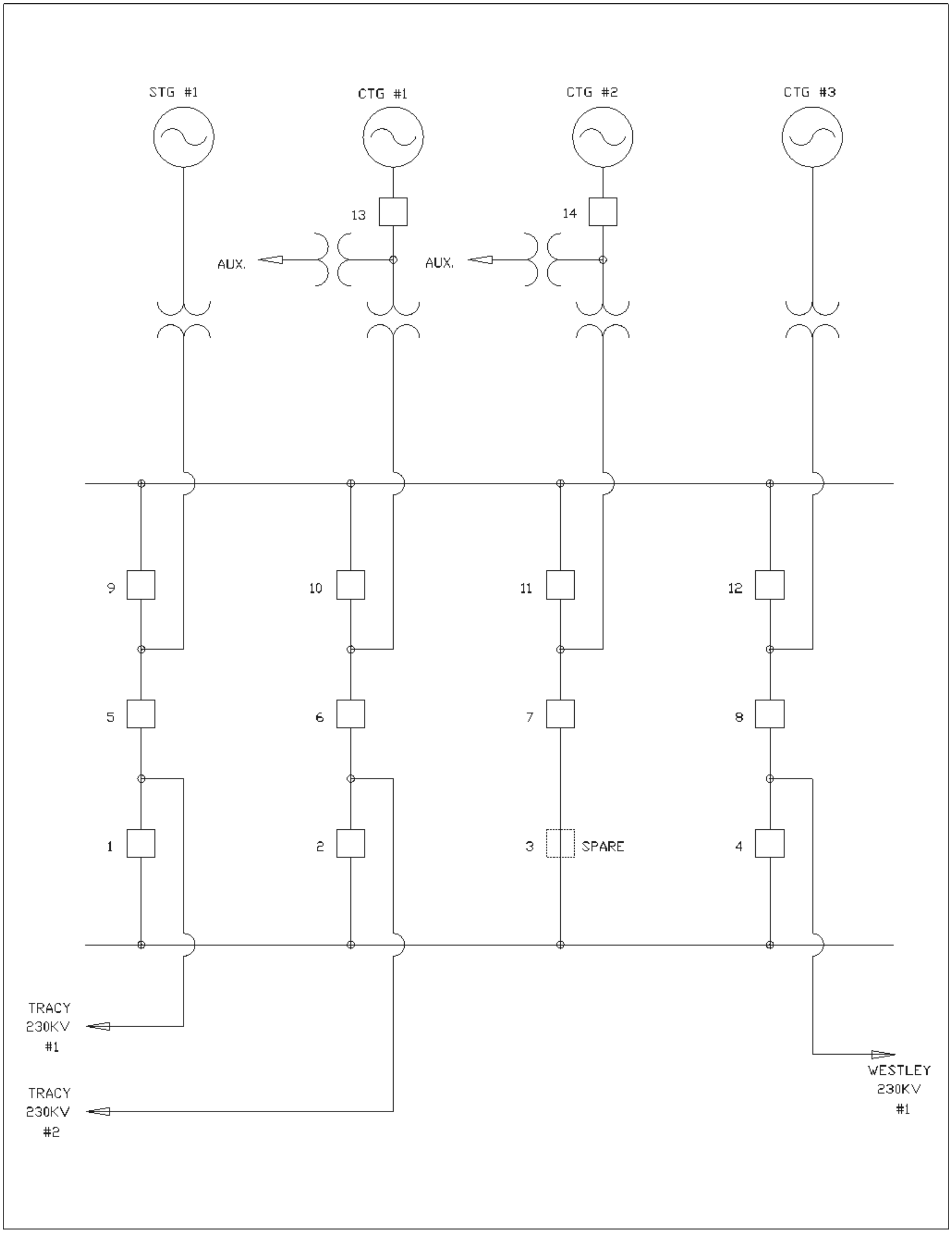
(CITY & CO OF SF)
(SUPERVISORY FROM MOCCASIN PH)
LINE RENAME COMPLETE 07-01-98
ELECTRONIC UPDATE 10-21-98
13 08-26-98
12 12-06-97
NO DATE
CHECKED BY
PWR CONT SAB
RWP
DIV DAA
OPERATING DIAGRAM
SAN JOAQUIN VALLEY REGION
(STOCKTON DIVISION)
230KV SHEET NO. 3
DATE: 10-1-85 APPROVED BY: RJM/DGL
P.G.& E. CO. DRAWING NO. 55235 13
NOTE: NO - DENOTES NORMALLY OPENED SWITCHES.

FIGURE 5.1-4


SHASTA
2-105 MVA
1-118 MVA, 2-128 MVA
(to be uprated to 128 MVA all 5 units by 2000)
TRINITY
2-74 MVA
TRINITY - JUDGE FRANCIS CARR
13.02 MI. SC STEEL
795 MCM ACSR 26/7
125' R/W
SHASTA - FLANNAGAN
2.53 MI. SC STEEL
795 MCM ACSR 26/7
360' & 500' R/W TO KESWICK
CAPTAIN JACK (BPA)
MALIN (BPA)
J.F. CARR
2-92 MVA
SPRING CREEK - KESWICK
2.13 MILES SC STEEL
1,272 MCM ACSR 45/7
125' R/W
SHASTA - COTTONWOOD #1 & #2
29.51 MI. 795 MCM ACSR 26/7
22.21 MI. SC STEEL, 7.30 MI. DC STEEL
360' & 500' R/W TO KESWICK
200' R/W
SPRING CREEK
2-100 MVA
J.F. CARR - KESWICK
#1 CIRCUIT 11.20 MI
795 MCM ACSR,26/7 DC STEEL
#2 CIRCUIT 11.32 MI.
954 MCM ACSR,45/7 SC,DC STEEL
125' R/W
FLANAGAN
(SHASTA LAKE)
AIRPORT - COTTONWOOD
.52 MI. DC STEEL 1272 MCM ACSR 45/7
9.18 MI. SC STEEL 795 MCM ACSR 26/7
100' R/W
MALIN - ROUND MT. NO.1
94.27 MILES SC STEEL
2 - 1780 MCM ACSR 84/19
175' R/W
100'
75'
FLANNAGAN-KESWICK
8.2 MI. SC STEEL
795 MCM ACSR 26/7
WHISKEYTOWN
1-3.92 MVA
KNAUF
AIRPORT
KESWICK
3-30 MVA
CENTRAL
VALLEY
TO KESWICK
115-KV
ROUND
MOUNTAIN
(PG & E)
KESWICK - AIRPORT
.52 MI. DC STEEL 1272 MCM ACSR 45/7
10 MI. SC STEEL 795 MCM ACSR 26/7
100' R/W
337.5' R/W
KES TO CW TAPS
TO REDDING
(2)
ROUND MT. - COTTONWOOD #1
33.50 MI. SC STEEL
795 MCM ACSR 26/7
125' R/W TO TOWER 2/2
137.5' R/W TO TOWER 15/5
147.5' R/W TO TOWER 32/6
FOLSOM - NIMBUS
6.6 MI. SC CONCRETE
336.4 MCM ACSR 26/7
150' R/W
OLINDA - CAPTAIN JACK
148 MI SC STEEL
3-1946.6 MCM ACSR/TWD
42/7 PER PHASE
200' R/W
COTTONWOOD - OLINDA #1&2 8.36 MI. DC STEEL
1,272 MCM ACSR 45/7, 1,272 MCM ACSR 45/7
250' R/W; 125' VACANT R/W NORTH OF SHA-CW
NIMBUS
2-8.63 MVA
COTTONWOOD - ROSEVILLE
70.15 MI. 1272 MCM ACSR 45/7
11.76 MI. 954 MCM ACSR 54/7
58.09 MI. 795 MCM ACSR 26/7
SC STEEL; 100' R/W
KESWICK-OLINDA
16.17 MI. DC STEEL
1,272 MCM ACSR 45/ 7
FOLSOM - ROSEVILLE
7.03 MI. SC STEEL
954 MCM ACSR 54/7
250' R/W
OLINDA
(TANC/WESTERN)
COTTONWOOD
(PG & E)
FOLSOM
2-71.7 MVA
OLINDA - TRACY
79.90 MI. SC STEEL
3-1565 MCM BITTERN ACSR/TWD
PER PHASE
125' R/W
OLINDA - ELVERTA
146.28 MI. DC STEEL
1,272 MCM ACSR 45/7
160' R/W TO TOWER 98/1
FOLSOM
1-71.7 MVA
ROSEVILLE
FIDDYMENT - ELVERTA
7.1 MI. DC STEEL
1,272 MCM ACSR 54/19
ROSEVILLE - ELVERTA
13.10 MI. DC STEEL
1,272 MCM ACSR 54/19
250' R/W
KESWICK - ELVERTA
161.70 MI. DC STEEL
1,272 MCM ASCR 45/7
125' R/W TOWER 98/1 TO 125/4
112.5' R/W TO 144/1
125' R/W TO 157/4
225' R/W SHARED WITH
CW-RSC 157/4 TO 160/3
ROSEVILLE - FIDDYMENT
6 MI. DC STEEL
1,272 MCM ACSR 54/19
FIDDYMENT
(ROSEVILLE)
ELVERTA
(SMUD)
ELVERTA
(WESTERN)
(TANC/WESTERN)
MAXWELL
ELVERTA - HURLEY #1
10.99 MI. DC STEEL
795 MCM ACSR 26/7
ELVERTA - HURLEY #2
10.73 MI. DC STEEL
954 MCM ACSR 45/7
200' R/W SHARED
WITH SMUD TO
TOWER 18/2
OLINDA -TRACY
114.17 MI. SC STEEL
3-1565 MCM BITTERN ACSR/TWD
PER PHASE
125' R/W
HURLEY
(SMUD)
TRACY - BANKS
0.185 MI. SC STEEL
2.135 MI. DC STEEL
1,565 MCM ACSR/TW 38/7
BANKS
(FUTURE)
HURLEY - TRACY #2
51.78 MI. 1,272 MCM
ACSR 45/7 SC STEEL
7.82 MI. 954 MCM
ACSR 45/7 DC STEEL
2.43 MI. 1,272 MCM
ACSR 45/7 DC STEEL
125' R/W STARTING AT TOWER 18/2
TRACY -LLNL
2.135 MI. DC STEEL
10.6 MI. SC STEEL
795 MCM ACSR 26/7
120' R/W
HURLEY - TRACY #1
59.11 MI. 795 MCM ACSR 26/7
7.36 MI. DC STEEL, 51.75 MI. SC STEEL
2.43 MI. 1,272 MCM ACSR 45/7 DC STEEL
125' R/W STARTING AT TOWER 18/2
TRACY
2-2300 MCM AAC
61 STRAND
CONDUCTOR
8 MI.
LAWRENCE
LIVERMORE
715.5MCM AA;
2 MILES
954 MCM
AAC
STRAND
2-CON-
DUCTOR/
PHASE
795 MCM ACSR;
2 MILES
YGNACIO
(CCWD)
CONTRA COSTA
(CCWD)
HERDLYN
(PG&E)
TESLA
(PG&E)
(2)
TESLA
(PG&E)
LOS BANOS
(PG&E)
LOS VAQUEROS
(CCWD)
WESTLEY (MID/TID)
(2)
TRACY-LOS VAQUEROS
69-KV 8.1 MI.
266.8 KCM 26/7 ACSR 2.5 MI. WOOD
795 MCM ACSR 26/7 12.2 MI. DC STEEL
LOS VAQUEROS TAP IS 5.6 MI. FROM TRACY SUB.
125' R/W
TRACY - YGNACIO
69KV - 40.8 MI.
795 MCM ACSR 26/7 12.2 MI., DC STEEL
266.8 MCM ACSR 26/7 7.2 MI., SC WOOD
3/0G CWC 21.38 MI., SC WOOD
125' R/W TRACY TO DELTA ROAD
50' AVG. R/W DELTA ROAD TO YGNACIO (10'-140')
SYMBOL KEY
500 kV
230 kV
115 kV
69 kV
POWERPLANT
INTERCONNECTION
NON-WESTERN FACILITIES
SUMMARY OF CIRCUIT MILES
500 kV-448.3 CKT MILES
230 kV-838.1 CKT MILES
115 kV-7.4 CKT MILES
69 kV-48.3 CKT MILES
TOTAL CKT MILES = 1,342.1
A 4-26-99 N5-JPV REDRAWN ON CAE GENERAL REVISIONS
UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION
SIERRA NEVADA REGION - FOLSOM, CALIFORNIA
SIERRA NEVADA REGION
CALIFORNIA
TRANSMISSION SYSTEM
DIAGRAM
DESIGNED B. DIENER
APPROVED MORTEZA SABET DIRECTOR, SYSTEM PLANNING & ENGINEERING
MARCH 21, 1993
SYP N
4



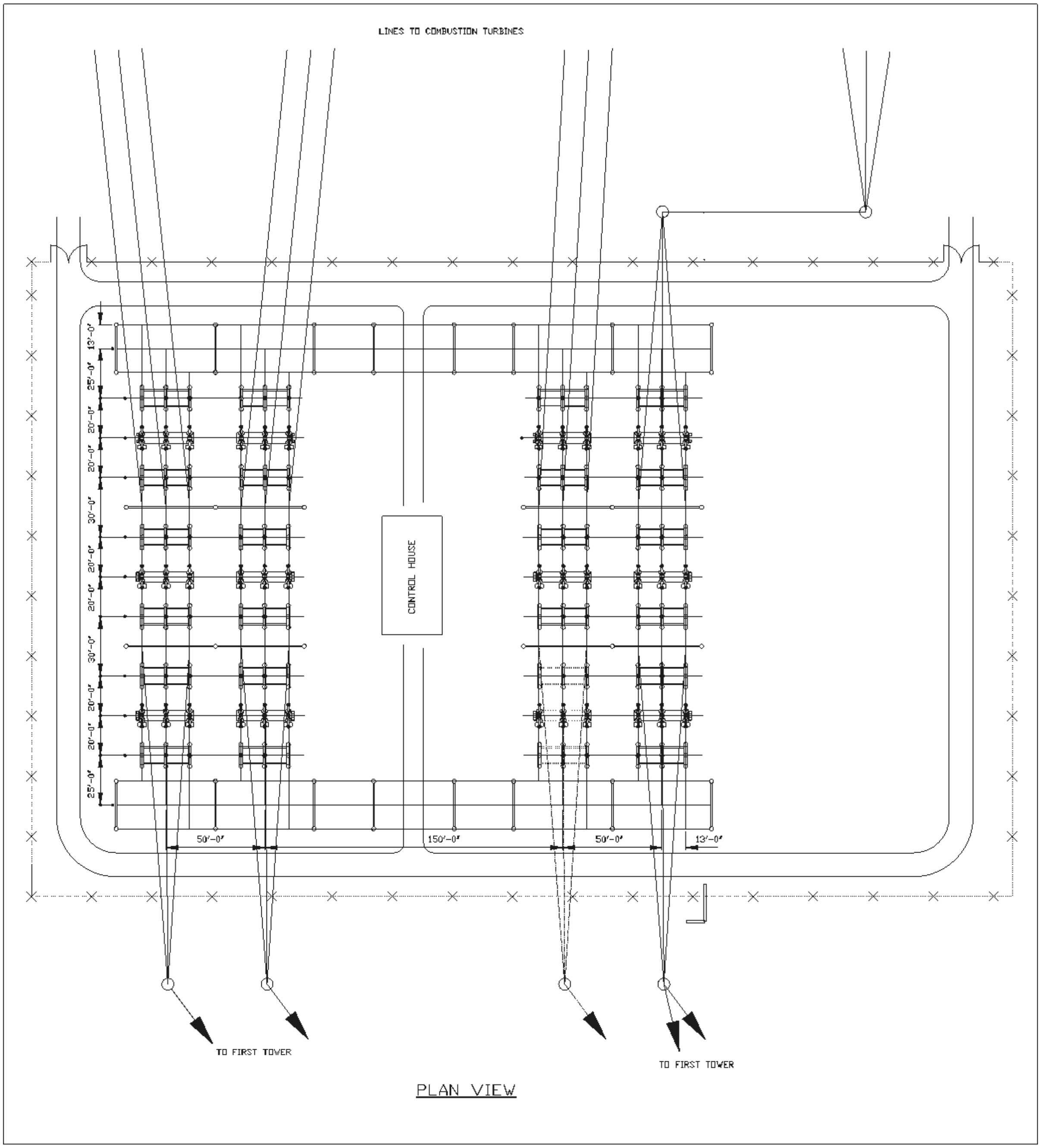
One-Line Schematic of the Proposed 230 kV Switchyard

Figure 5.2-1

January 8, 2001

East Altamont Energy Center - Calpine Corporation

Prepared By:
Commonwealth Associates Inc.
Jackson, Michigan
Engineers Consultants Construction Managers



Layout of the Proposed 230 kV Switchyard

East Altamont Energy Center - Calpine Corporation

Figure 5.2-2

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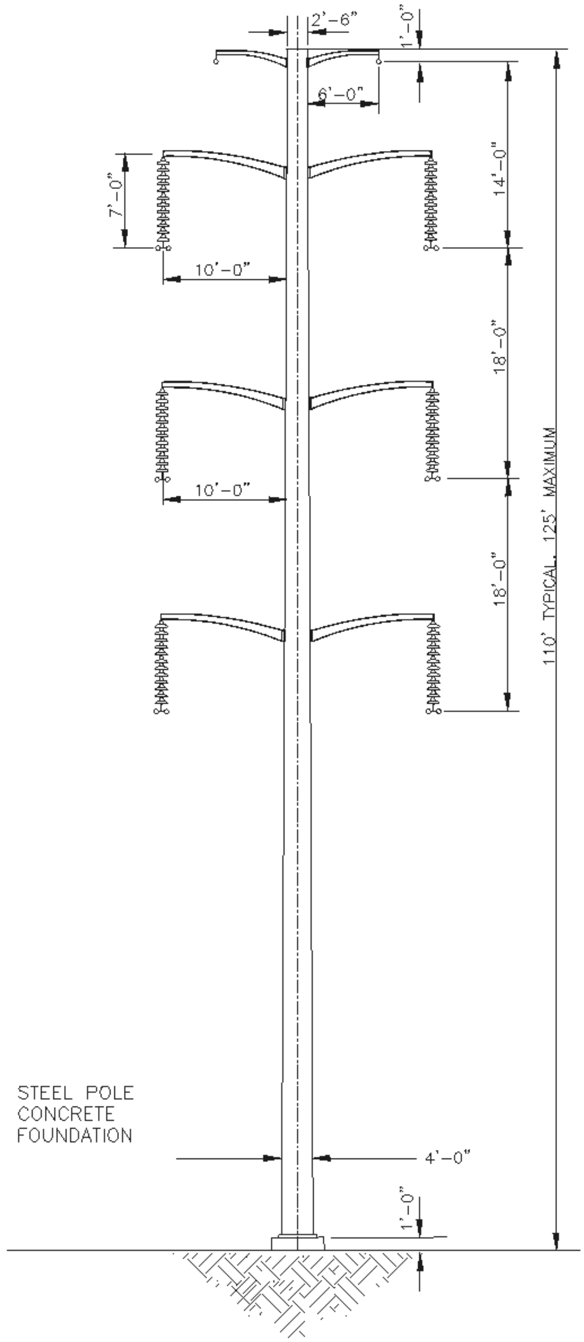
Engineers Consultants Construction Managers



230 kV DOUBLE-CIRCUIT TANGENT STRUCTURE
(Approximate Dimensions)

Double-Circuit Tangent Structure (Pole)

Figure 5.2-3

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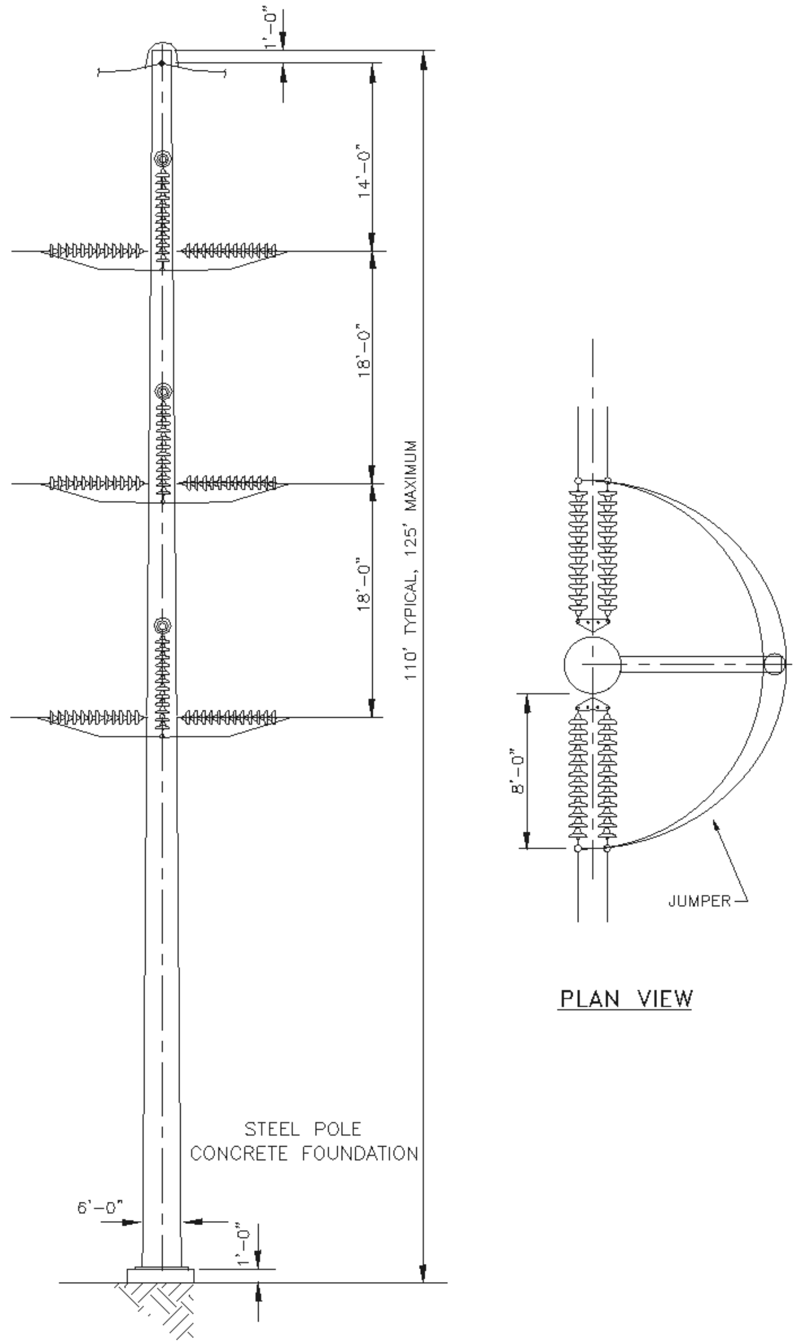

230 kV TYPICAL SINGLE-CIRCUIT PULL-OFF STRUCTURE
(Approximate Dimensions)

Single-Circuit Pull-Off Structure

Figure 5.2-4

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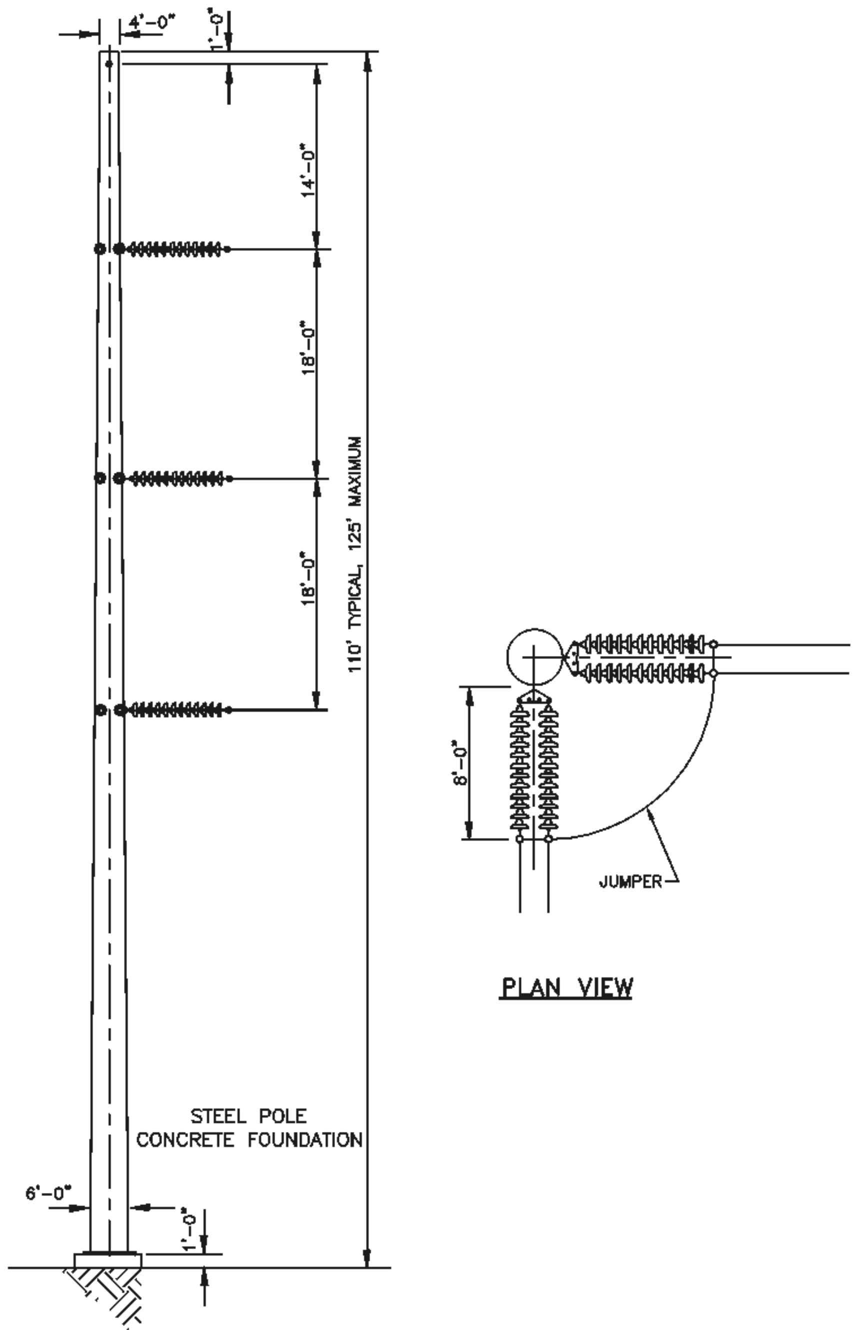

230 kV TYPICAL SINGLE-CIRCUIT 90°ANGLE DEAD-END STRUCTURE
(Approximate Dimensions)

Single-Circuit 90° Angle Dead-End Structure

Figure 5.2-5

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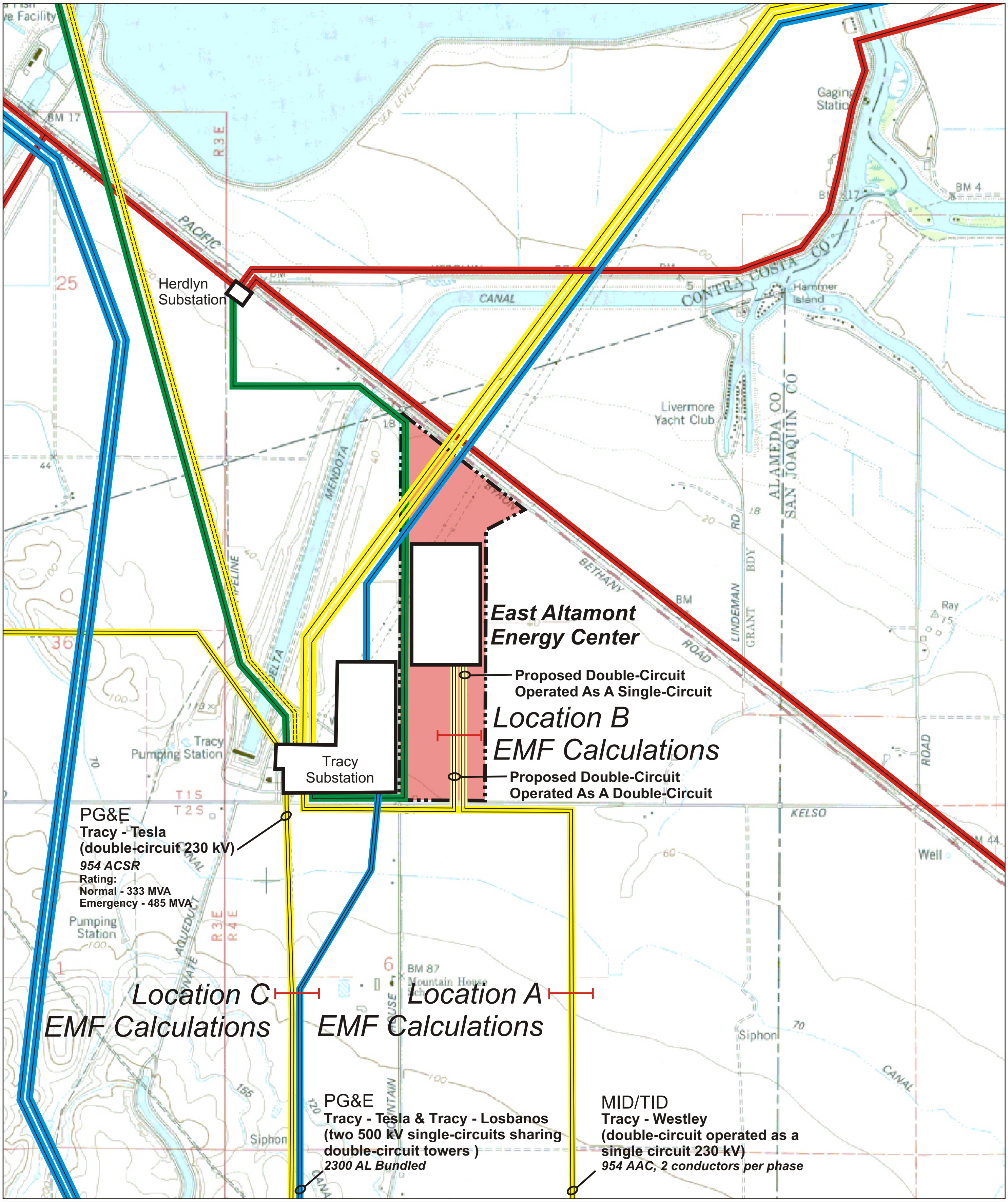


Existing 500 kV Transmission Line
Existing 230 kV Transmission Line
Existing 230 kV Transmission Line (not energized)
Existing 69 kV Transmission Line
Existing 60 kV Transmission Line
Proposed Transmission Line
Cross Section Site For EMF Calculation

N W E S

Scale: 1" = 2000'

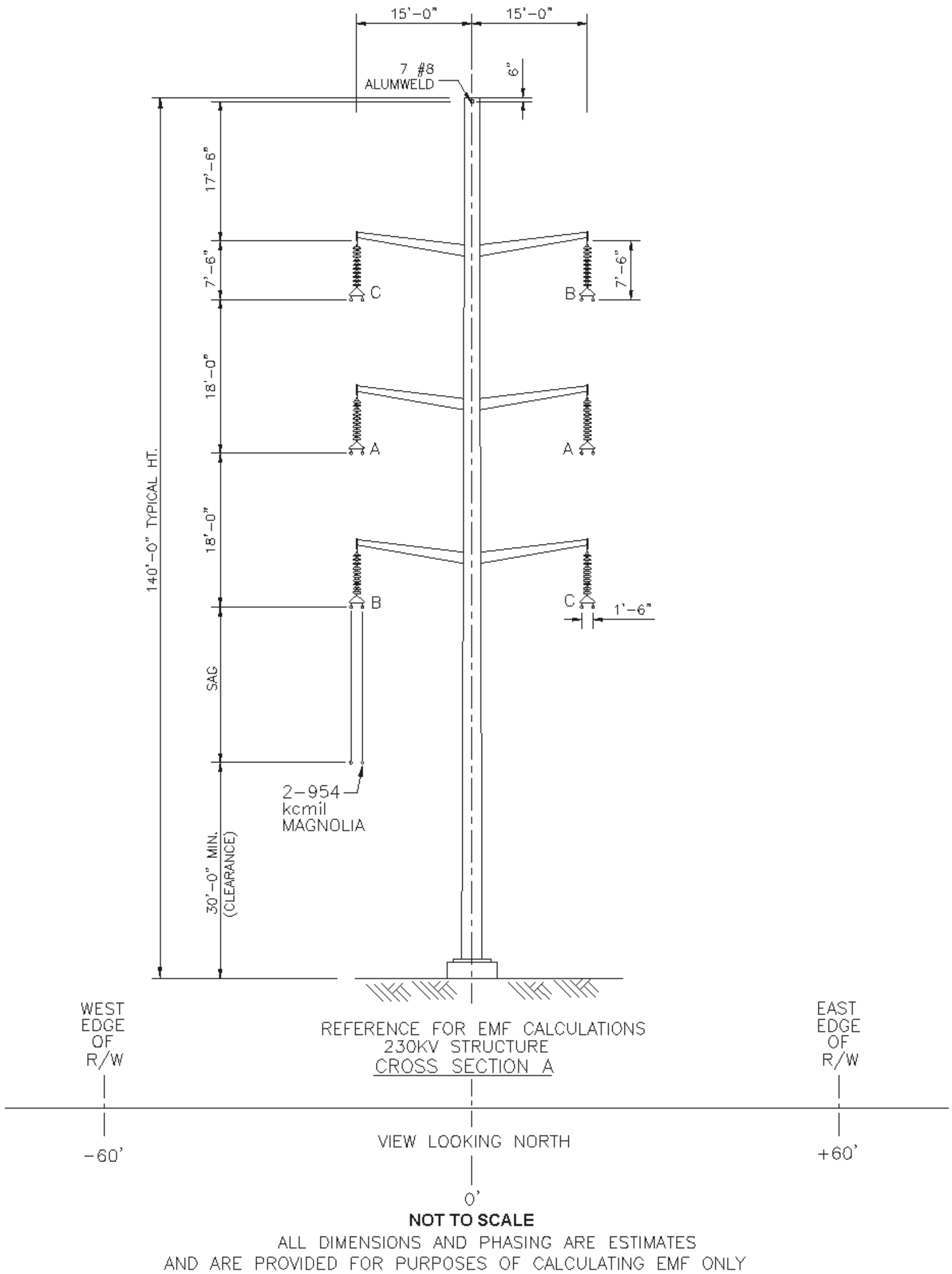
0 500 1000 1500 2000
FEET

California
Map Area

FIGURE 5.5-1
Transmission in the Vicinity of the Proposed East Altamont Energy Center
Calpine
January 8, 2001

Prepared By:
CAI Commonwealth Associates Inc.
Jackson, Michigan
Engineers • Consultants • Construction Managers

Basemap: Sure!Maps Raster - USGS 7.5 Minute Topographic Quadrangle Maps.



Cross Section A
230 kV Typical Double-Circuit Structure

Figure 5.5-2

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Calpine Corporation

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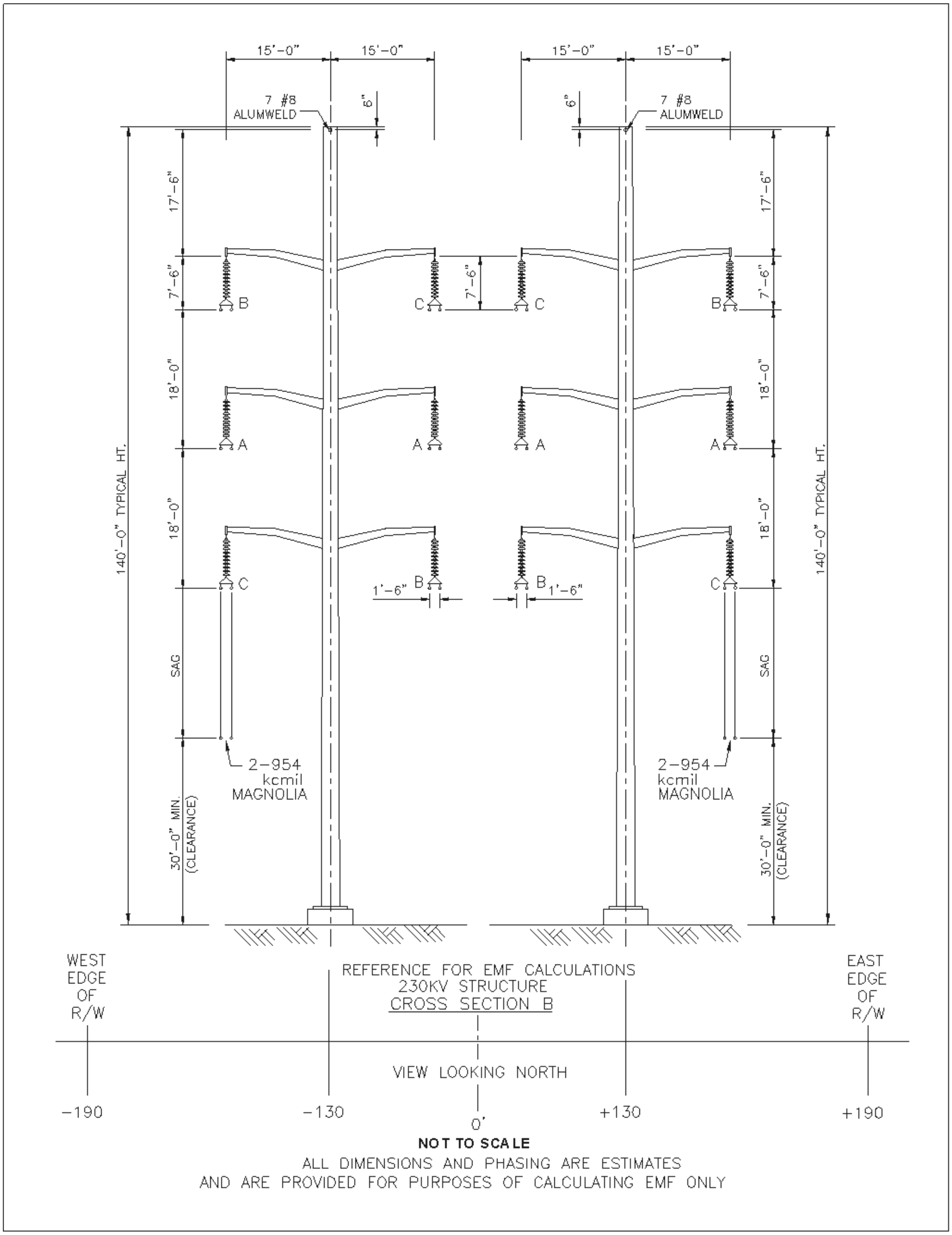

Cross Section B
230 kV Typical Double-Circuit Structures

Figure 5.5-3

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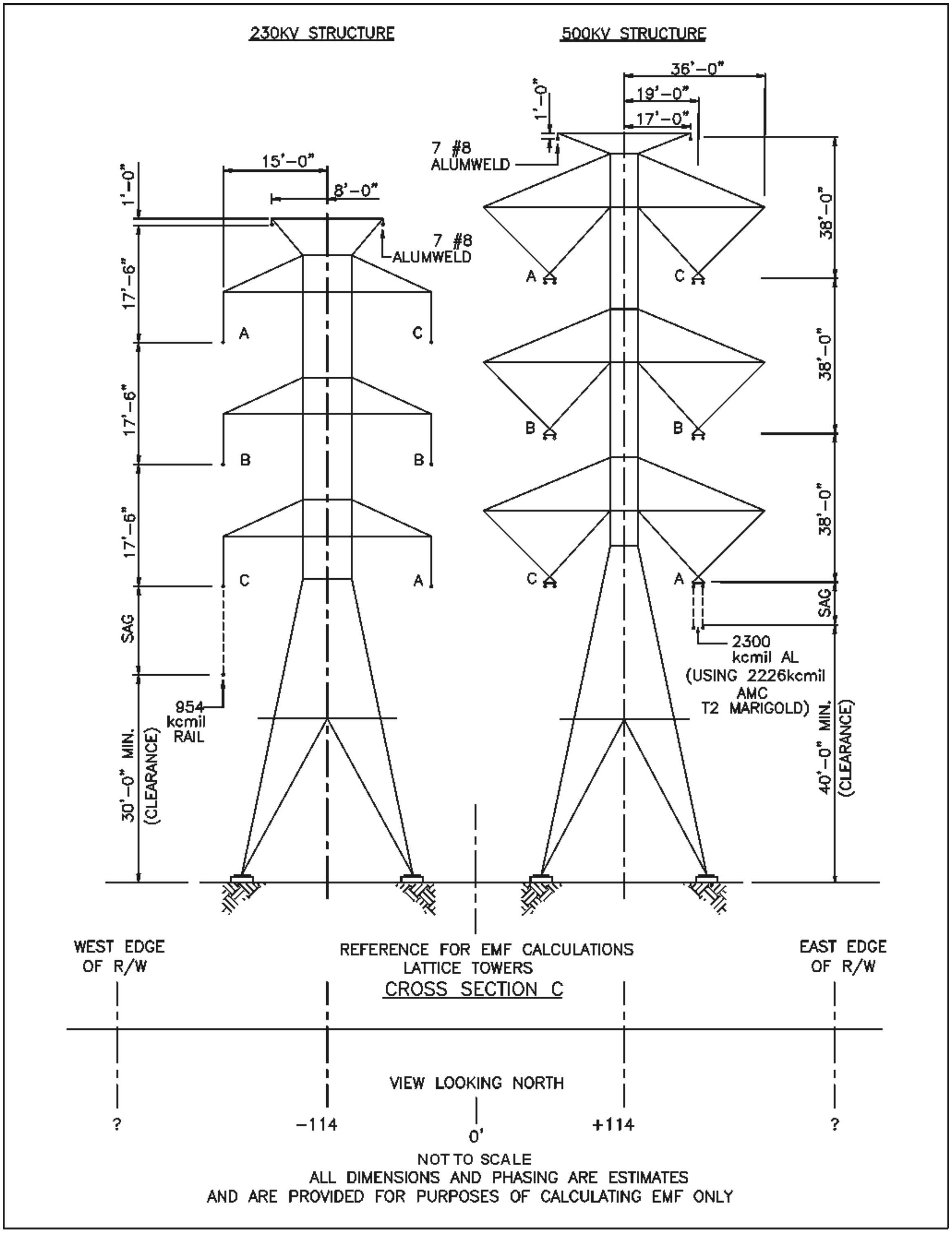

Cross Section C
230 kV & 500 kV Typical Double-Circuit Structures

Figure 5.5-4

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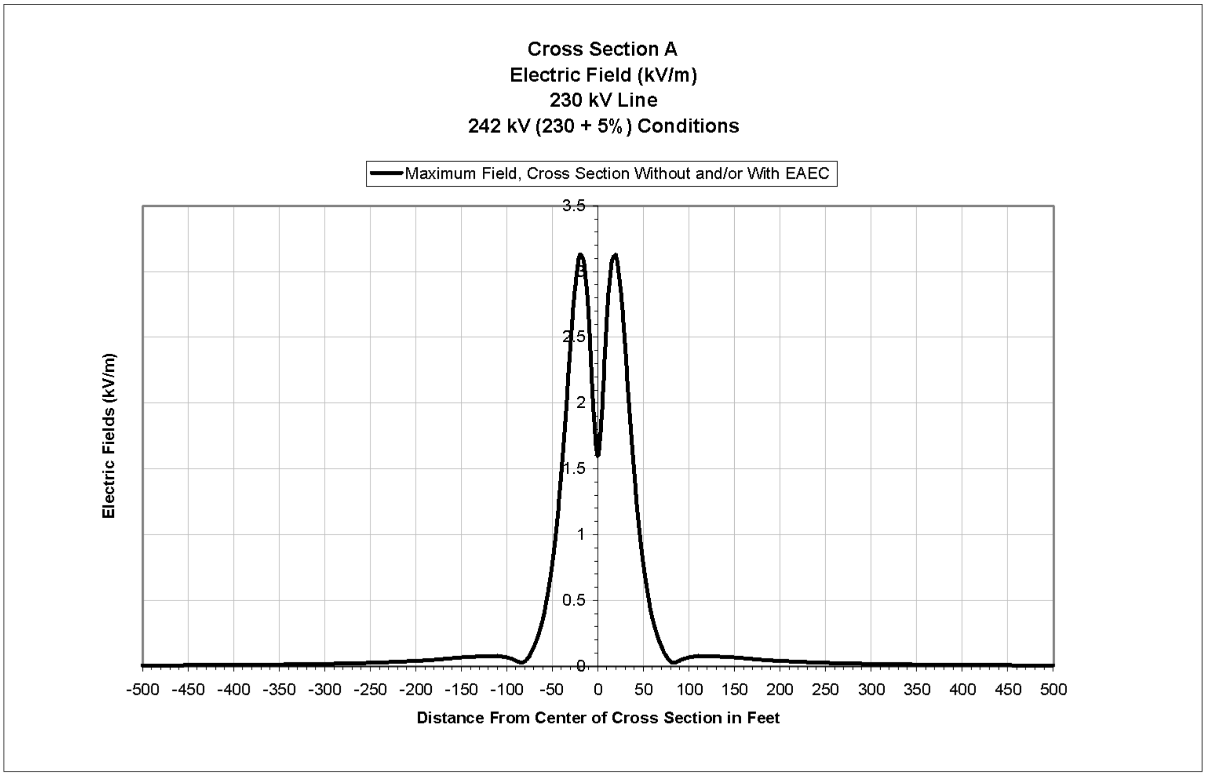

Cross Section A - Electric Field

East Altamont Energy Center - Calpine Corporation

Figure 5.5-5

January 8, 2001

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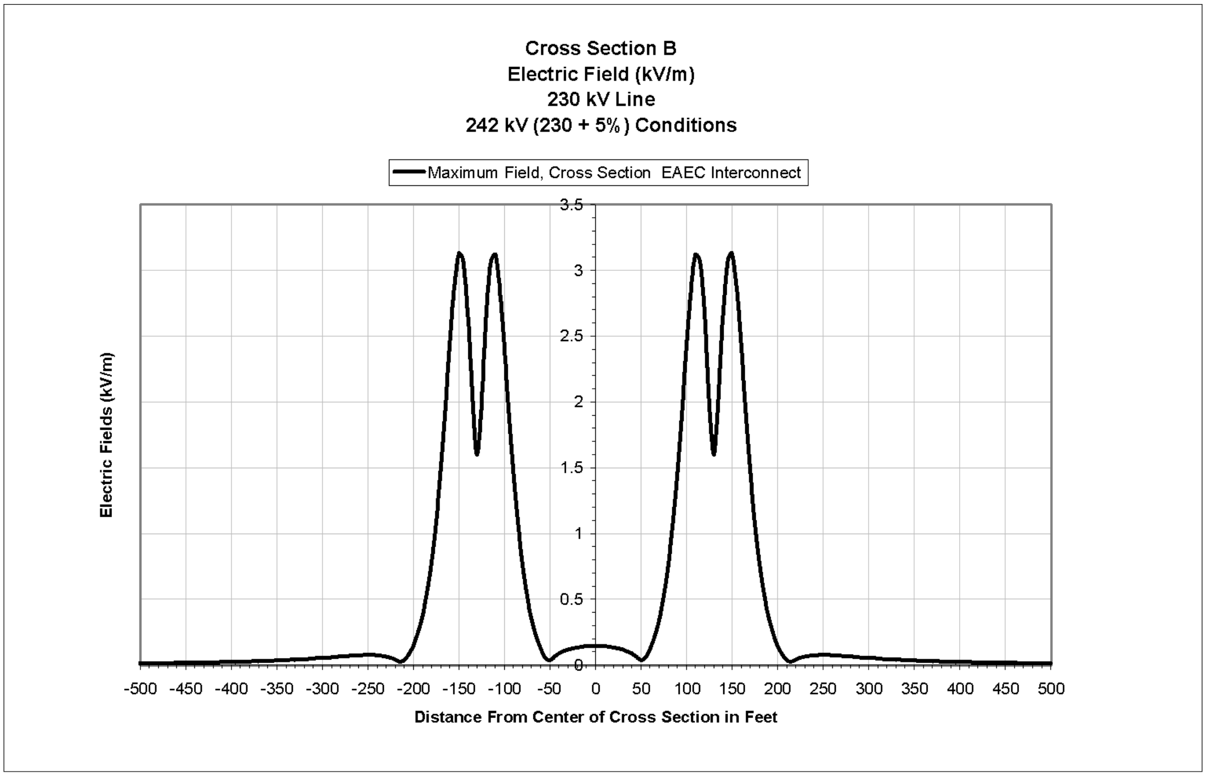

Cross Section B - Electric Field

East Altamont Energy Center -
Calpine Corporation

Figure 5.5-6

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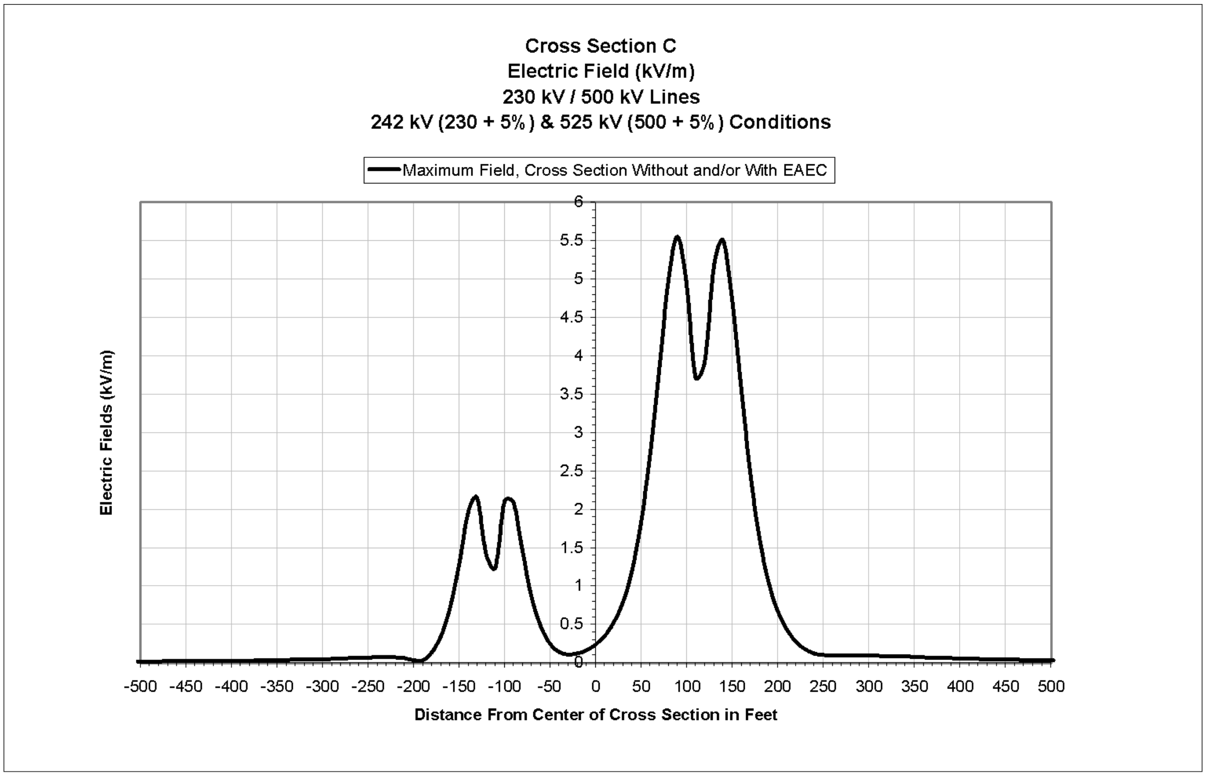

Cross Section C - Electric Field

Figure 5.5-7

East Altamont Energy Center - Calpine Corporation

January 8, 2001

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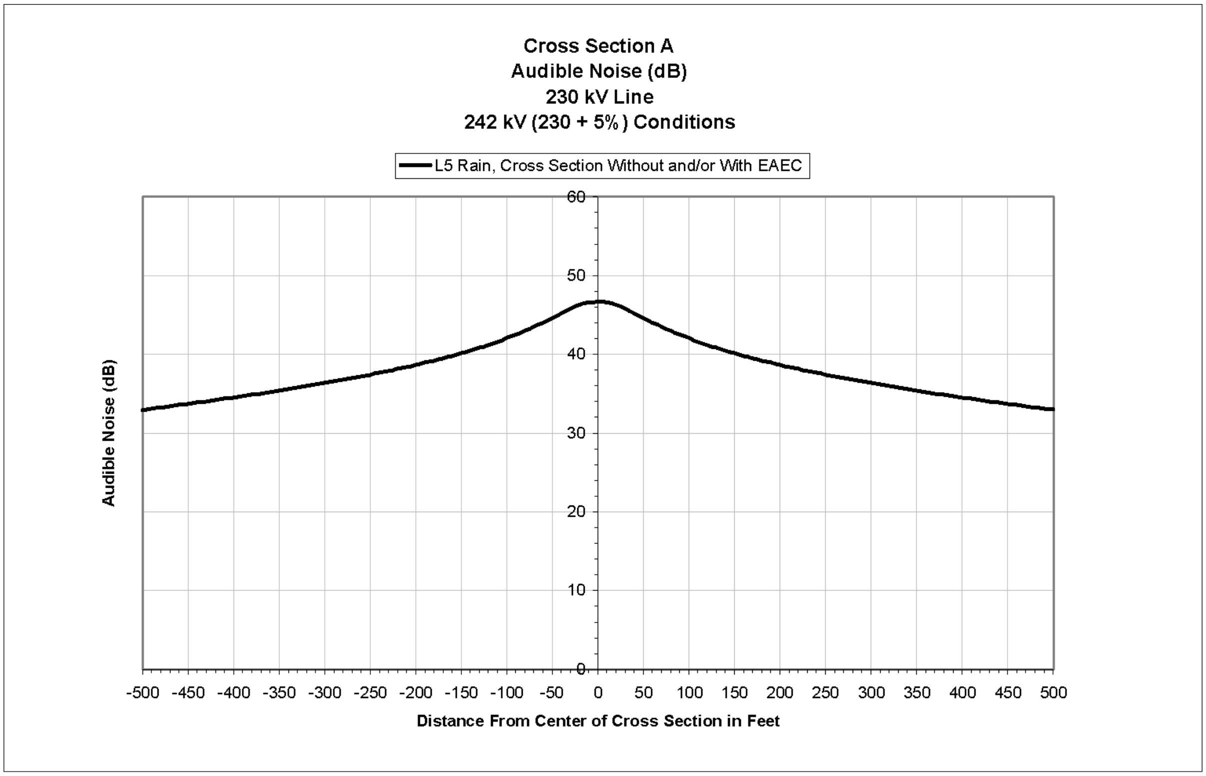

Cross Section A - Audible Noise

East Altamont Energy Center - Calpine Corporation

Figure 5.5-8

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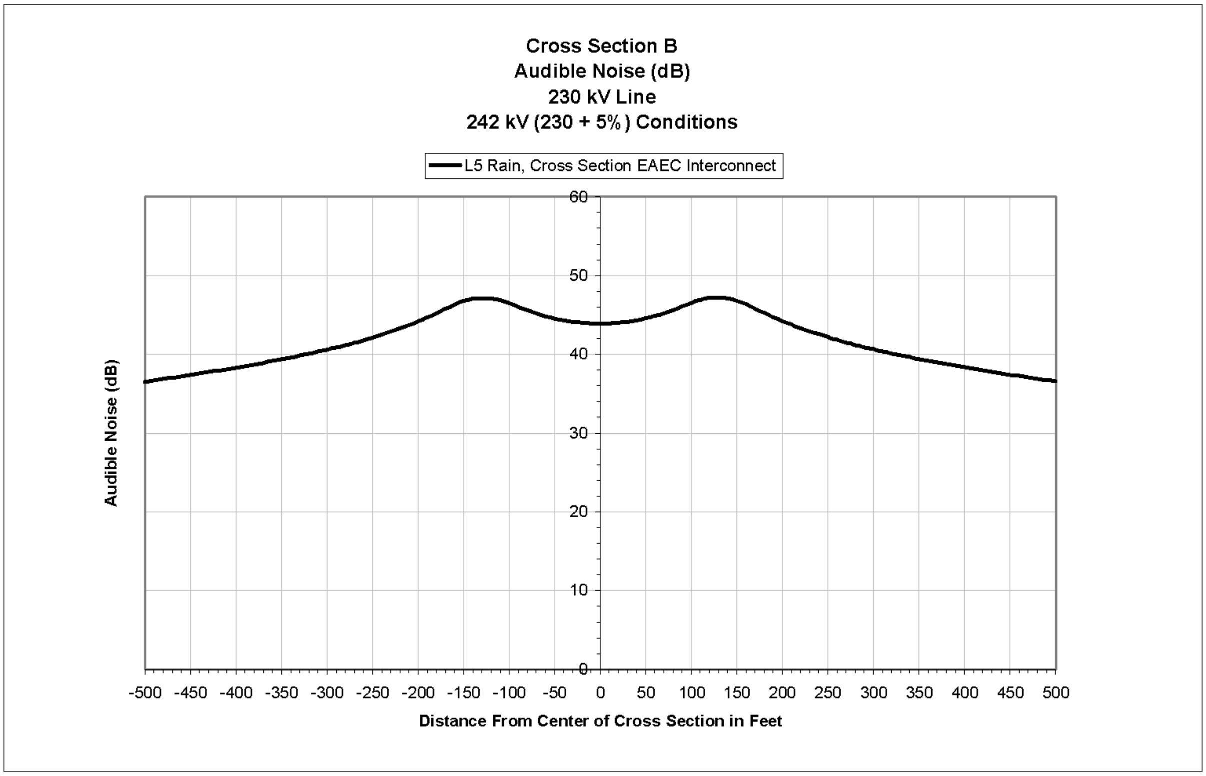

Cross Section B - Audible Noise

Figure 5.5-9

January 8, 2001

East Altamont Energy Center - Calpine Corporation

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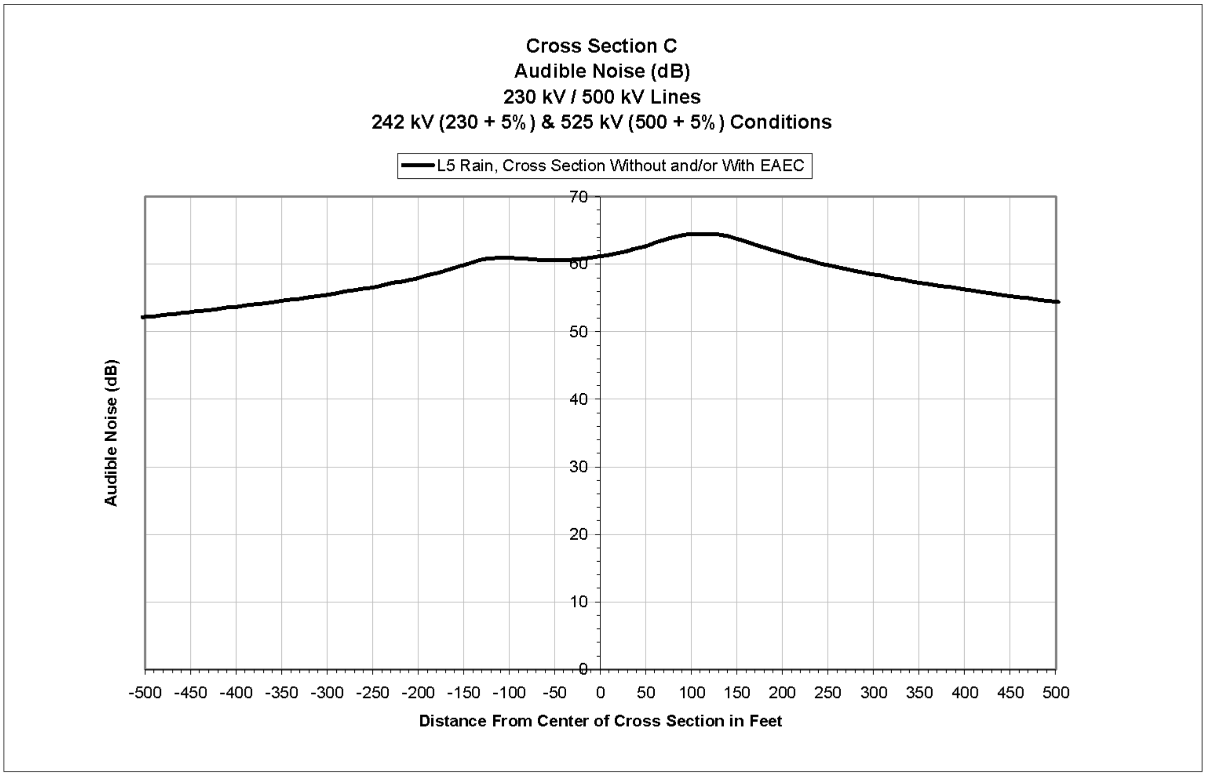

Cross Section C - Audible Noise

East Altamont Energy Center - Calpine Corporation

Figure 5.5-10

January 8, 2001

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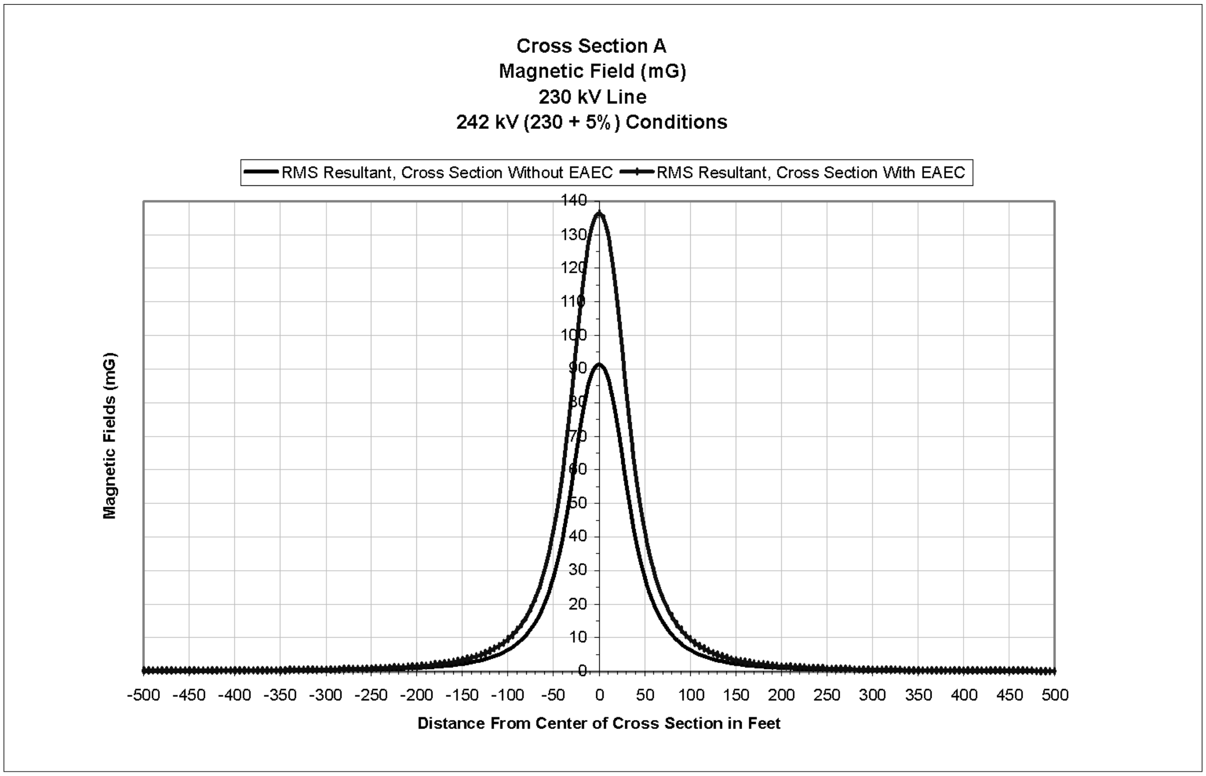

Cross Section A - Magnetic Field

East Altamont Energy Center - Calpine Corporation

Figure 5.5-11

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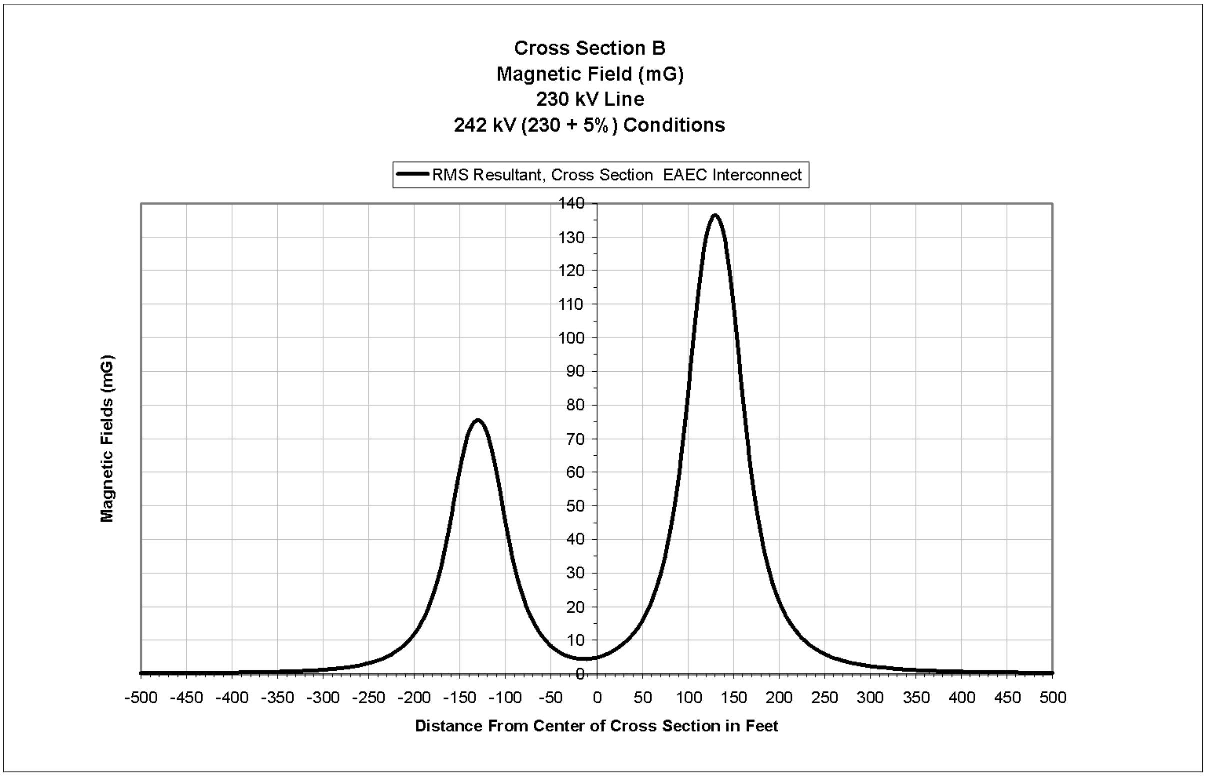

Cross Section B - Magnetic Field

East Altamont Energy Center - Calpine Corporation

Figure 5.5-12

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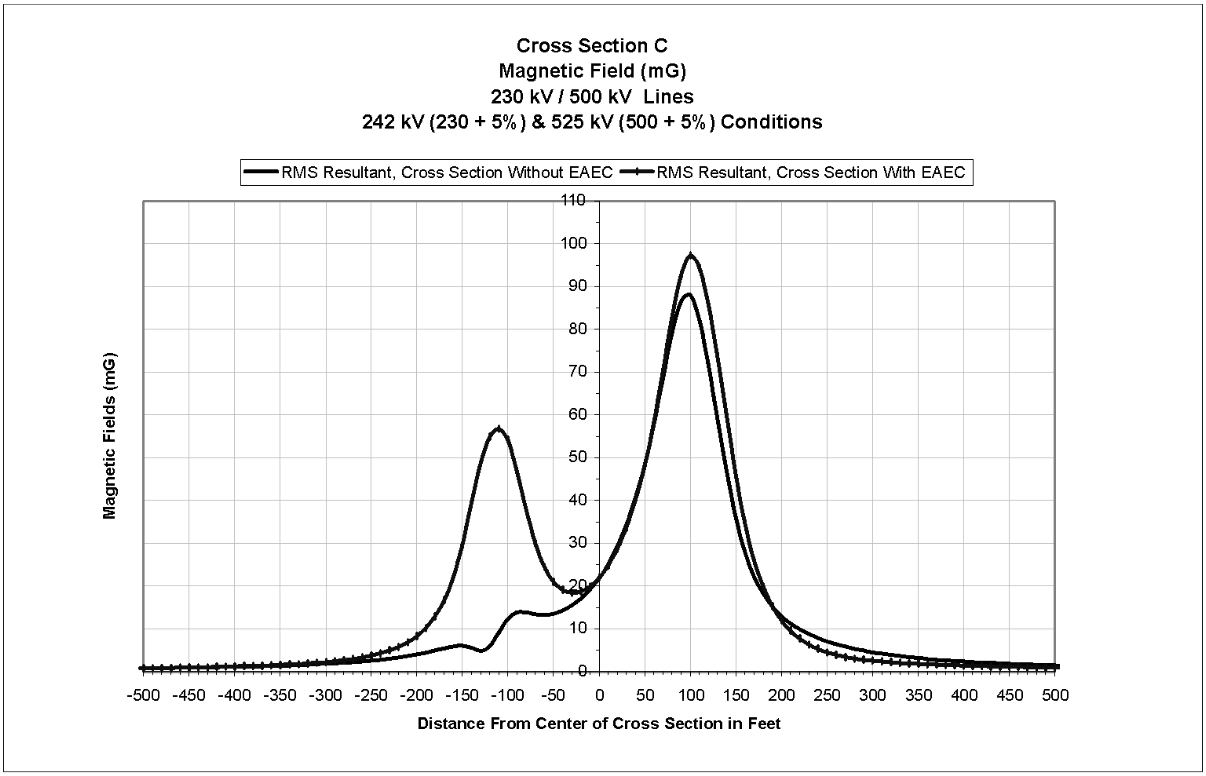

Cross Section C - Magnetic Field

East Altamont Energy Center - Calpine Corporation

Figure 5.5-13

January 8, 2001

Prepared By:
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Jackson, Michigan
Engineers Consultants Construction Managers

6.0 Natural Gas Supply

This section discusses the natural gas supply for the EAEC project. Section 6.1 describes the preferred gas supply line route, and Section 6.2 describes the alternative routes. Section 6.3 discusses the selection criteria. The gas supply line construction methods and the pipeline operating procedures are described in Section 6.4. Pipeline operations are described in Section 6.5. Section 6.6 lists the permits and permitting schedule.

Natural gas would be obtained from a PG&E transmission backbone pipeline located approximately 1.5 miles west of the project site (Figure 6.1-1). A 20-inch pipeline would be constructed from the PG&E pipeline tap point to the EAEC site.

6.1 Preferred Route

The preferred natural gas pipeline route (Route 2a) is approximately 1.4 miles long and ties into the PG&E main pipeline. The pipeline would run south on Mountain House Road, and turn west under or parallel to Kelso Road, west to the PG&E main pipeline. Construction would be by open trench.

6.2 Alternative Routes

In addition to the preferred Route 2a, to determine the optimal route for the gas supply pipeline, alternative routes were evaluated. All of these routes appear feasible.

The three alternative routes considered for the natural gas supply pipeline are described below:

Alternative 2c. This alternative is approximately 1.4 miles long and ties into the PG&E main pipeline near the corner of Kelso and Bruns roads. From the project site, the pipeline runs south on Mountain House Road to the corner of Kelso Road. From there it turns southwest at approximately 260 degrees for approximately 0.4 mile until it crosses the Delta-Mendota Canal. From that point it turns northwest at approximately 280 degrees to meet the main pipeline near the corner of Kelso and Bruns roads. Construction is primarily by open trench, but might require horizontal directional drilling (HDD) or jack and bore where it crosses the Delta-Mendota Canal.

Alternative 2d. This alternative is approximately 1.5 miles long and ties into the PG&E main pipeline approximately 1.1 mile south of Kelso Road. From the project site, the pipeline runs south on Mountain House Road to the corner of Kelso Road. From there it turns southwest at approximately 250 degrees for approximately 0.3 mile until it crosses BBID's Canal 45. From that point it turns south for a distance of approximately 0.8 mile, following approximately the edge of the section line. Approximately 300 feet north of the main pipeline, it takes the shortest and most efficient route to the pipeline, potentially heading directly west, or directly south, as determined by site-specific engineering constraints and consultations with PG&E. Construction would be by open trench.

Alternative 2e. This alternative is approximately 1.2 miles long and ties into the PG&E main pipeline approximately 0.8 mile south of Kelso Road, near where the Delta-Mendota Canal emerges from an underground tunnel into an open canal. From the project site, the pipeline runs south on Mountain House Road to the corner of Kelso Road. From there it turns southwest at approximately 250 degrees for approximately 0.3 mile until it crosses BBID's Canal 45. From that point it turns approximately 195 degrees, parallel to the buried Delta-Mendota Canal for approximately 0.7 mile. The pipeline runs parallel to the Delta-Mendota Canal from 50 to 250 feet from the toe of the canal berm, as determined by final engineering and consultations with both Delta-Mendota and the landowner. Construction would be by open trench, but might require HDD or bore and jack where it crosses any jurisdictional wetlands.

6.3 Selection Criteria

The route and alternative gas pipeline alignments were selected on the basis of engineering/ construction feasibility, length of pipeline, cost, and the potential for environmental impacts:

- Engineering/construction feasibility is an assessment of whether the pipeline can be physically placed along a given route.
- Length of pipeline is important because pressure drop, cost, and potential environmental impacts are usually functions of length.
- Cost is an important factor dictated by the deregulated electricity market and the need to keep new generating facilities competitive.
- Environmental impacts must be either not significant or mitigatable to a less than significant level.

There are significant differences in environmental sensitivity between the various routes. All gas supply pipeline routes primarily pass through land that is already disturbed, either by a roadway or agricultural uses. Potential resources that could be affected by the pipeline include biological, cultural/paleontological, agriculture and soils, and traffic and transportation. The preferred route has been field-surveyed for biological and cultural/ paleontological impacts. Potential impacts from the construction and use of proposed routes are discussed in Sections 8.2, 8.3, 8.9, and 8.16, and potential impacts from the alternative routes are presented in Section 9.0, Alternatives. Table 6.3-1 compares the preferred and alternative natural gas pipeline routes to the selection criteria.

Alternative 2a, the preferred route, is slightly shorter than either 2c or 2d. Alternative 2e is shorter still, but would potentially require additional permits to trench through jurisdictional wetlands. Alternative 2a would potentially disrupt traffic on Kelso Road, but is less likely to disturb biological resources.

TABLE 6.3-1
Comparison of Natural Gas Pipeline Routes

Characteristic	Preferred Route (2a)	Alternative 2c	Alternative 2d	Alternative 2e
Engineering/Construction Feasibility	Yes	Yes	Yes	Yes
Length of Pipeline	1.4 miles	1.4	1.5	1.2
Probability of Environmental Impacts	Low	Moderate	Moderate/High	Low/Moderate

6.4 Construction Practices

The natural gas pipeline would be constructed with a minimum of at least one crew ("spread") working continuously along the pipeline ROW. Depending on project schedule requirements, additional crews may be required. Construction of the entire pipeline would require a peak workforce of approximately 40 workers. Some workers would park in the construction laydown area for the EAEC site and be transported to the construction area along the pipeline ROW by crew cab trucks, bus, or van. Other workers, such as welders, equipment operators, and crew foreman, would take their vehicles directly to the ROW and use these vehicles during construction activities. The ROW would be accessed over existing roads to the extent feasible. Most major pieces of construction equipment may remain along the ROW during the course of construction. Besides providing worker parking, the EAEC site would serve as the location for storing pipe and other pipeline construction materials. Additional storage locations would be in existing paved or graveled areas along the pipeline route. Pipeline construction would take approximately 2 to 3 months and is expected to occur during summer 2003.

The temporary ROW for gasline construction will be 75 to 85 feet wide, containing a 25-foot-wide spoils side to store excavated earth material and a 55-foot-wide working side for the trench and pipeline construction equipment. If necessary, additional materials storage locations may be located along the pipeline ROW. A permanent 50-foot-wide easement to facilitate leak inspection and related monitoring or maintenance activities will be required.

The line pipe would be of alloyed carbon steel material in accordance with the American Petroleum Institute (API) specification for line pipe. A factory-applied corrosion protection coating would be applied on the pipe. Joints would be welded.

The construction of the natural gas pipeline would consist of the following activities:

1. **Trenchin**g – Trenching would consist of excavating a trench that will be roughly up to 8 feet wide at the top and 3 feet wide at the bottom. Trench width depends on the type of soils encountered. Trench depth will be sufficient to meet the requirements of the governing agencies. However, the pipeline will be buried to provide a minimum cover of 36 inches. The excavated soil will be piled on one side of the trench and used for backfilling after the pipe is installed in the trench. The pipeline will be installed through trenching at all locations except where boring or directional drilling is required to pass beneath a road, natural water course, or canal; or to avoid sensitive areas.

2. **Stringing** – Stringing consists of trucking lengths of pipe to the ROW and laying them on wooden skids beside the open trench.

3. **Installation** – Installation consists of bending, welding, and coating the weld joint areas of the pipe after it has been strung, padding the ditch with sand or fine spoil, and lowering the pipe string into the trench. Bends will be made by a cold bending machine or shop-fabricated as required for various changes in bearing and elevation. Welding would meet the applicable API standards and be performed by qualified welders. Welds would be inspected in accordance with API Standard 1104. Welds will undergo 100 percent radiographical inspection by an independent, qualified radiography contractor. All coating will be checked for holidays (i.e., defects) prior to lowering into the trench.

4. **Backfilling** – Backfilling consists of returning spoil back into the trench around and on top of the pipe, ensuring that the surface is returned to its original grade or level. The backfill will be compacted to protect the stability of the pipe and to minimize subsequent subsidence.

5. **Plating** – Note: Plating is not normally required.

6. **Boring** – The boring method may be used for moderately short crossings under roads, canals, sensitive habitats, or where dictated by governmental agency, or where it would be environmentally unsound to use the open cut method. Boring pits will be dug on each side of the crossing. On the inlet side, an auger-bearing boring machine will be used, or a ramming device may be used to "jack and bore" pipe into place. "Jack and bore" is less expensive on a per-foot basis than HDD.

7. **Horizontal Directional Drilling** – HDD, which could be used to route the pipeline under wetlands, canals, and major roads, involves specialized construction procedures. The HDD equipment initially drills a pilot hole, which is followed by a pilot hole drill string. A reaming device is then attached to the drill string and pulled through the pilot hole. The reamer enlarges the pilot hole to a diameter of 35 to 50 percent greater than the final pipeline size. The pipeline then is welded, radiographed, hydrotested, and pulled through the enlarged borehole.

8. **Drilling Mud** – Drilling mud is used as part of the HDD process to lubricate and cool the drill. The mud is non-toxic bentonite. The drilling mud will be collected at the directional drilling site and disposed of at a Class III landfill.

9. **Hydrostatic Testing** – Hydrostatic testing consists of filling the pipeline with water, venting all air, increasing the pressure to the specified code requirements, and holding the pressure for a period of time. It is important that freshwater be used for testing. After hydrostatic testing, the test water is chemically analyzed for contaminants and discharged into a dewatering structure consisting of hay bales, geotextile fabric, and silt fencing. The discharged water filters through the hay bales and silt fence onto jute matting before it is discharged. Temporary approvals for test water use and permits for discharge will be obtained as required.

10. **Cleanup** – Cleanup consists of restoring the surface of the ROW by removing any construction debris, grading to the original grade and contour, and revegetating and repairing where required.

11. **Commissioning** – Commissioning consists of cleaning and drying the inside of the pipeline, purging air from the pipeline, and filling the pipeline with natural gas. Depending on the timing of first gas consumption, an inert gas such as nitrogen could be used to purge the line prior to filling with natural gas.

12. **Safety** – A construction safety plan will be prepared for the project. This plan will address specific safety issues, traffic control, working along traveled county streets, and other areas as required by permits.

6.4.1 Metering Station

A gas metering station will be required at the interconnection point with PG&E's transmission pipeline. The metering station will require an area of approximately 1/2 acre (150 feet by 150 feet). The metering station will require a power source. The primary power source will be an electrical line from the nearest utility distribution line. Solar power may be used as backup.

Construction activities related to the metering station will include grading a pad; installing aboveground gas piping, metering equipment; and possibly gas conditioning, pressure regulation, and pigging facilities. A distribution powerline for metering station operation lighting, communication equipment, and perimeter chain link fencing for security will also be installed.

6.5 Pipeline Operations

The preferred natural gas supply pipeline will be designed, constructed, and operated in accordance with Title 49, Code of Federal Regulations, Part 192 (49 CFR 192). Specifically, the pipeline will be designed in accordance with the standards required for gas pipelines in proximity to populated areas, based on actual population densities along the preferred pipeline route. It will be buried a minimum of 36 inches, or deeper, as required by Federal Code.

An operations and maintenance plan will be prepared, addressing both normal procedures and conditions, and any upset or abnormal conditions that could occur. Periodic cathodic protection surveys will be performed along the pipeline, as required by 49 CFR 192. The pipeline will be continuously protected by a cathodic protection system.

The applicant will implement a proactive damage prevention program for the proposed pipeline. Markers identifying the location of the pipeline will be placed at all road crossings. The markers will identify a toll-free number to call prior to any excavation in the vicinity of the pipeline.

The transported gas will be as received from PG&E's main pipeline. The owners of the proposed pipeline will develop an emergency plan to provide prompt and effective responses to upset conditions detected along the pipeline or reported by the public.

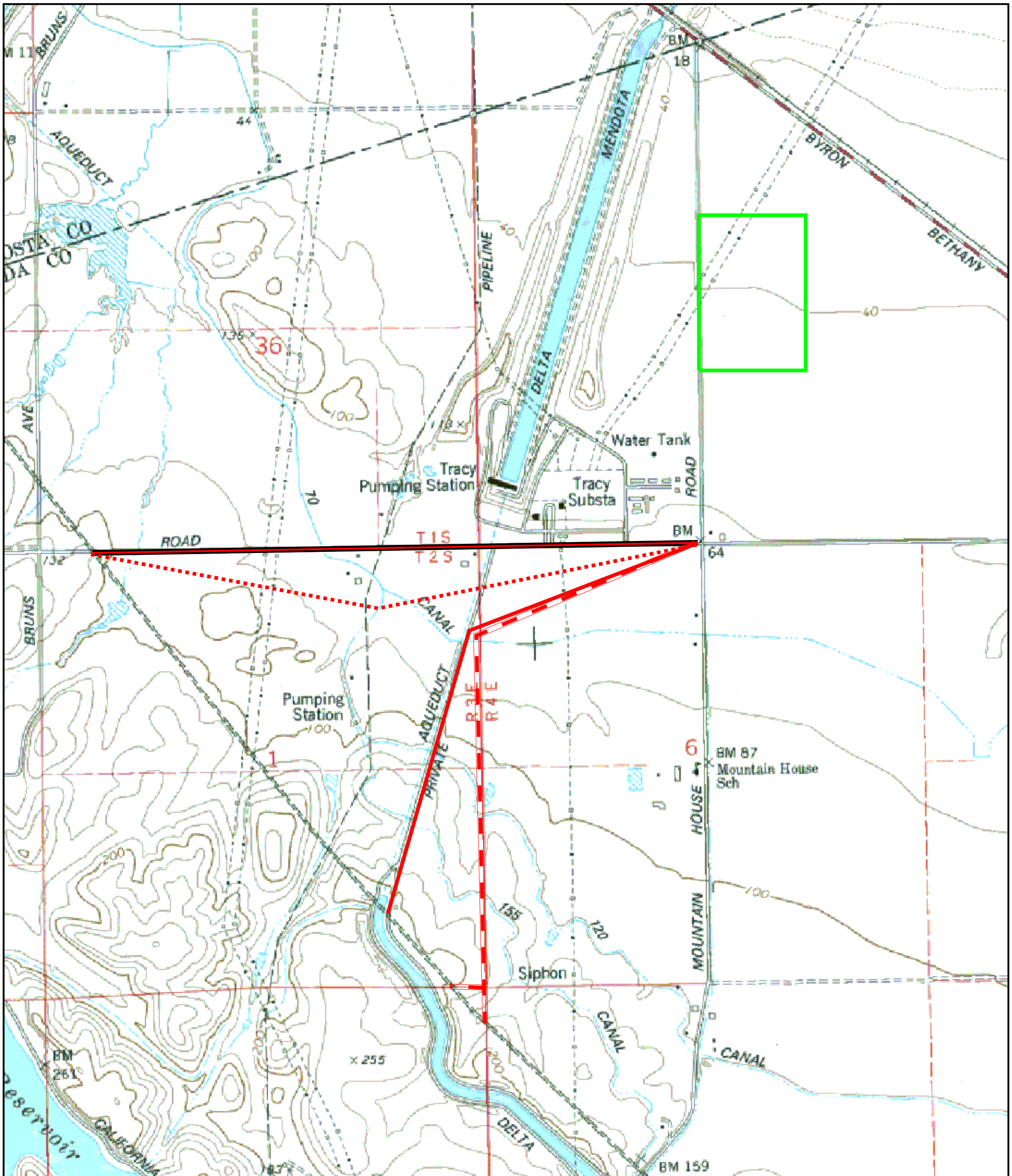
Isolation block-valves will be installed at both ends of the preferred alternative pipeline. These valves will be manually controlled, lockable, gear-operated ball valves. PG&E will have access to the isolation block-valve at the mainline tap; either EAEC or PG&E will have access to the downstream isolation ball valve at the EAEC property. PG&E will own and operate a metering facility to measure the gas supply to EAEC. A pipeline Supervisory Control and Data Acquisition (SCADA) system will provide flow rate and pressure data to PG&E and EAEC. Communication with PG&E gasline operations will be by dedicated telephone lines or other means, such as Cellular Digital Pocket Data (CDPD).

6.6 Permits and Permitting Schedule

The California Streets and Highways Code, Division 2, Chapter 5.5, Sections 1460-1470, mandates that an encroachment permit must be obtained from the County Public Works Department if there is an opening or excavation for any purpose in any highway. This and other permits, as well as the schedule for obtaining the permits, is presented in Table 6.6-1. A copy of the interconnection letter from PG&E is presented in Appendix 6.1A.

TABLE 6.6-1
Permit Schedule for Gas Supply Lines

Permit	Schedule	Contact
Franchise Agreement (if necessary)	6 weeks to 6 months	Alameda County Public Works Development Services John Byers 399 Elmhurst St. Hayward, CA 94544-1345 510/670-5429 ext. 55429
Easement	3 months to 6 months	Individual landowners along route
Alameda County Encroachment Permit	6 weeks to 6 months	Alameda County Public Works Development Services John Byers 399 Elmhurst St. Hayward, CA 94544-1345 510/670-5429 ext. 55429



LEGEND

PROJECT SITE

COMMUTER RAIL SERVICE

REGIONAL BUS
TRANSIT SERVICE

GAS

2A PREFERRED

2C

2D

2E

N

1000 0 1000 Feet

SCALE IS APPROXIMATE

FIGURE 6.1-1
GAS LINE ALTERNATIVES

APPLICATION FOR CERTIFICATION
FOR EAST ALTAMONT ENERGY CENTER

CH2MHILL

CH2M Hill RDD ArcView Project File \\Thor\Cart1\rddgis\east_alt\east_alt.apr fig6_1_1.pdf 5:43 p.m. 03-13-2001

7.0 Water Supply

This section describes the proposed water supply sources and alternatives for the EAEC. Section 7.1 discusses the cooling water sources, and possible alternatives for the water supply pipeline routes. This section also discusses the selection criteria for assessing the alternatives and proposed construction practices. Section 7.2 discusses domestic use water, and Section 7.3 discusses process makeup water. A map of the project site is presented as Figure 2.1-1.

The EAEC would require approximately 4,600 AF of water in a typical year. During normal operation, approximately 95 percent of that water would be used for condensing the steam which exhausts from the plant's steam turbine. The remainder would be used for process makeup water to the steam cycle and for fogging of the combustion turbine inlet air. In peak demand years, water use could be as high as 7,000 AF.

Water for the project would be supplied from three sources: raw water, recycled water, and groundwater. Byron Bethany Irrigation District (BBID) will provide water to meet the project 's cooling and process makeup water demands. BBID is the irrigation district that serves the project vicinity and has two potential sources of water. Initially, BBID would supply raw water from its existing surface water supply. An onsite water treatment system would treat and condition the incoming BBID raw water for use in the cooling towers, the production of demineralized water for fogging of the combustion turbine inlet air and to produce steam within the HRSG and for injection into the gas turbine for power augmentation.

BBID is currently developing a recycled water feasibility study for its service area. As recycled wastewater becomes available from the Mountain House Community Services District wastewater treatment plant (MHCSD WWTP), BBID would supply recycled water to replace as much BBID raw water as feasible. A portion of BBID raw water would continue to be needed, however, for process makeup water and to meet peak day cooling requirements. The buildout of facilities providing recycled water from the MHCSD WWTP is anticipated to occur over the next 20 years.

The limited domestic demands (sanitary and washwater) for the project would be met with onsite groundwater or water from the federal facility to the south and west of the site. For the onsite water supply option, a well would be drilled and a wellhead treatment system installed to supply this minimal demand. There is a local domestic water treatment plant that serves the federal facilities across Kelso Road from the project. If water from the federal facility is used, a supply pipeline would be installed from the facility, across Kelso Road to the project site.

Local groundwater was considered as a potential raw water supply. However, the hydrology and water quality in the immediate project vicinity are not conducive to groundwater production for any significant uses such as process or cooling water. The estimated monthly water requirements for the project and the three sources of supply are shown in Table 7-1A and Table 7-1B for Year 1 and Year 20, respectively (see Section 2.0, Project Description, for additional information on the project's internal water balance). These water requirements are based on a "typical" year assuming full base-load operation for most of the year with peak operation, including combustion turbine power augmentation and HRSG duct firing, for 12 hours per day, 6 days per week, for the hottest 4 months of the year.

TABLE 7-1A
Estimated Monthly Water Requirements for EAEC – Year 1 (Typical Year assumed)

Water Demand Type	Monthly Requirements (AF)												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Raw Water from BBID	306	276	306	296	306	545	563	563	545	306	296	306	4,614
Recycled water from MHCSD WWTP	0	0	0	0	0	0	0	0	0	0	0	0	0
Other (for domestic uses)[a]	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	2
Total Monthly Water Use	306	276	306	296	306	545	563	563	545	306	296	306	4,616

[a]Water for domestic purposes would come from either on-site wells or from the local domestic water treatment plant which serves Western and the other federal and state facilities.

TABLE 7-1B
Estimated Monthly Water Requirements for EAEC – Year 20 (Typical Year assumed)

Water Demand Type	Monthly Requirements (AF)												
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Raw Water from BBID[a]	0	0	0	26	86	385	433	408	335	16	0	0	1,753
Recycled water from MHCSD WWTP[b]	306	276	306	270	220	160	130	155	210	290	296	306	2,861
Other (for domestic uses)[c]	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	2
Total Monthly Water Use	306	276	306	296	306	545	563	563	545	306	296	306	4,616

[a]Figures represent the amount of BBID raw water that would be used assuming the MHCSD WWTP develops as conservatively assumed; more or less would be required as MHCSD recycled water is made available.
[b]Monthly figures represent the minimum amount of water that is estimated would be consistently available from the MHCSD WWTP at buildout; actual availability may be greater depending on the timing of buildout.
[c] Water for domestic purposes would come from either on-site wells or from the local domestic water treatment plant which serves Western and the other federal and state facilities.

7.1 Cooling Water

The proposed cooling water supply sources for the project are BBID raw water and recycled water from the MHCSD WWTP. A description of BBID's water supply and water quality is provided below, as well as the proposed infrastructure required to deliver BBID water from its existing Canal 45 turnout to the project site. A description of the MHCSD WWTP recycled water supply and proposed infrastructure to bring recycled water to the project site is also provided. This section also describes and compares the alternative pipeline routes.

7.1.1 BBID Raw Water Supply

BBID is a multi-county special district established under state law for the primary purpose of providing water to the lands of Alameda County, Contra Costa County, and San Joaquin County. BBID acquired pre-1914 water rights with a priority date of May 18, 1914. BBID has an existing supply of approximately 60,000 AF of water each year based on its water rights posting. Table 7-2 shows BBID's water rights and its current and projected water demand. (Note that EAEC demands are not included in the projection because the projection was made prior to conception of the proposed EAEC project.) As illustrated in the table, sufficient water supply under BBID's existing water rights would be available to serve project demands even with BBID's projected demands.

TABLE 7-2
BBID Projected Average Annual Demands (AFY)

Demand Type	2000[a]	2010	2020	2030	2040
Total District Water Right	60,000	60,000	60,000	60,000	60,000
Agricultural Use	31,000	34,300	31,400	28,500	25,600
Identified Municipal and Industrial Use					
Discovery Bay West	-	500	500	500	500
Unimin Industrial Use	700	1,500	1,500	1,500	1,500
Mountain House (RWSA 1)	-	4,641	9,415	9,415	9,415
Tracy Hills (RWSA 2)	-	6,000	6,000	6,000	6,000
East County Airport	-	1,100	1,200	1,200	1,300
Byron	-	500	600	700	700
Subtotal—Identified M&I Use	**700**	**14,241**	**19,215**	**19,315**	**19,415**
Total —Agricultural and Identified M&I Use	**31,700**	**48,541**	**50,615**	**47,815**	**45,015**

Source: CH2M HILL, 1999
[a] Revised 2000 data per discussion with Rick Gilmore, BBID Manager (August 2, 2000)

BBID raw water, coupled with recycled water from MHCSD WWTP as it becomes available, is the most appropriate water source for the project. The facility is located in the BBID service area. Other water sources that were investigated and considered infeasible are as follows:

- Onsite groundwater supplies are not proposed because water quality (see Table 8.14-1) is exceptionally poor and there is insufficient demonstrated yield to meet project demands from the basin underlying the project site. In the part of the groundwater basin that might have sufficient yield to meet project cooling water demands, other domestic water users are utilizing the basin, and pumping to meet project demands could adversely affect those users.
- Irrigation return flows are not available in sufficient quantities year-round to meet project demands. The salinity of those flows would result in a greater waste flow and higher treatment costs than those resulting from the proposed source.
- The Applicant is committed to using recycled water when it becomes available from BBID. There are presently no existing sources of recycled water available to the project site.

The proposed infrastructure required to deliver BBID water from its existing Canal 45 turnout to the project site would consist of a pump station located at the intersection of Canal 45 and Bruns Road and a new 24-inch pipeline to the site. This infrastructure is described below.

7.1.1.1 Proposed Raw Water Pump Station Facility

The pump station for the Preferred Alternative (Alternative 3e), and Alternatives 3a and 3d, would be located on the southwest corner of Bruns Road and BBID's Canal 45. The location of the proposed raw water pump station is presented in schematic form as Figure 7.1-1. The pump station would be capable of pumping at 7,765 gpm to meet peak daily delivery (6,371 peak demand with a maximum 8-hour curtailment). Hourly peak demands would be met with onsite storage. The pump station would consist of 3 or 4 pumps, sized to allow the total peak demand to be met when one pump is down. If necessary, the BBID pumps at its intake pump station will be upsized and one or more pumps will be provided with variable speed motors to better match the downstream demand pattern. However, no change in the intake structure is anticipated.

The pumps in the raw water pump station will be powered by electric motors in a fenced enclosure. Electric power would be provided to the pump station by the same service provider that supplies power for the BBID intake pump station, which supplies water to Canal 45. Estimated electrical power requirements would be approximately 600,000 kilowatt-hours per year (kWh/year) to provide full raw water supply to the project. These power requirements would not change appreciably (less than a 20 percent change) when recycled water replaces some of the BBID raw water supply.

In the event of power outage or mechanical system failure, water would be provided for cooling and process needs from onsite storage.

7.1.1.2 Alternative Raw Water Pipelines

Alternatives for the BBID raw water pipeline are shown in Figure 2.1-1 and described later in this section.

7.1.2 MHCSD WWTP Recycled Water Supply

The project is committed to using recycled water to the extent it is available. BBID is investigating the potential for developing a recycled water supply to supplement existing raw water supplies in its service area – especially for use at the proposed project. As the area's water purveyor, BBID would be responsible for distributing recycled water. Recycled water in excess of the project's water demands could be conveyed by BBID through its facilities to other customers to supplement BBID's raw water supplies. BBID is completing a feasibility study regarding the availability and use of recycled water, including estimates of the quality and quantity of recycled water that can be made available from the MHCSD WWTP. Next steps include further discussions and agreements between BBID and MHCSD, and BBID Board adoption of a recycled water plan. The Applicant is committed to using as much recycled water as BBID can provide for the project's needs. The estimates of the quantity and quality of recycled water from the MHCSD WWTP in this section were provided to The Applicant by BBID based on work performed as part of the Recycled Water Feasibility Study. The analysis of the potential availability of recycled water indicates that it would be feasible to use recycled water from MHCSD WWTP for a portion of the project water demands.

As the recycled water becomes available to BBID from the MHCSD WWTP, recycled water could be transported from a pump station located on MHCSD WWTP property to the project site. The pumps and the pipeline would be sized to supply 350 AF per month, to meet the requirements of the project. BBID may size the facility to serve a maximum of 700 AF per month for other users. A 24-inch pipeline would be required to supply 700 AF per month.

The Preferred Alternative pipeline route for recycled water (Alternative 4b on Figure 2.1-1) would be to install a pipeline from the site of the future MHCSD WWTP west along Bethany Road and then northwest along Byron Bethany Road to the project site. The MHCSD WWTP recycled water would be combined with BBID raw water, circulated through a cooling tower, and discharged to the zero discharge system onsite.

The pump station at the MHCSD would be similar to the pump station at the Canal 45 turnout for the BBID raw water supply. Similar to the BBID raw water pump station, the pump station would have a capacity of 7,765 gpm. The station would have 3 to 4 pumps sized so that the maximum demand could be met with one pump down. The same power provider that provides power to the MHCSD WWTP would provide power to the pump station. Electrical or mechanical system outage or failure could interrupt the proposed recycled water supply. To provide water during these periods, the project would use raw water from BBID or from onsite storage until systems were brought back online.

7.1.3 Cooling Water Quality

Cooling water would consist of a blend of raw and recycled water. Water quality of MHCSD is estimated using data from the Delta Diablo Sanitation District Plant (DDSD). Table 7-3 summarizes the quality of BBID raw water and DDSD effluent. DDSD effluent is considered worst case relative to inorganic quality because it is more heavily industrialized than the Mountain House area is planned to be. Table 7-3 also shows the anticipated mix of constituents for EAEC influent for Year 20, assuming that the ratio of raw water from BBID to recycled water from the MHCSD WWTP in Year 20 would be approximately 33 percent to 67 percent.

TABLE 7-3
Estimated BBID Raw Water Quality, DDSD Recycled Water Quality, and EAEC Cooling Tower Makeup Water Quality in Year 20

		Range of Water Quality Data			
		BBID Raw Water [a,b]			
Parameter	Units	Range	Mean	DDSD Recycled Water	Estimated EAEC Water Quality in Year 20 [c]
Calcium	mg/L	11 to 25	15	25	22
Magnesium	mg/L	2 to 14	8	2	4
Sodium	mg/L	17 to 65	28	150	110
Potassium	mg/L	4	4	13	10
Iron, dissolved	mg/L	.0025 to 0.19	0.03	0.246	0.17
Manganese	mg/L	<0.0025 to .057	0.02	0.023[d]	0.022
Ammonia as NH_4	mg/L	No data available	No data available	27	27 (does not include BBID data)

TABLE 7-3
Estimated BBID Raw Water Quality, DDSD Recycled Water Quality, and EAEC Cooling Tower Makeup Water Quality in Year 20

		Range of Water Quality Data			
		BBID Raw Water [a,b]			
Parameter	Units	Range	Mean	DDSD Recycled Water	Estimated EAEC Water Quality in Year 20 [c]
Sulfate	mg/L	14 to 59	30	180[d]	131
Chloride	mg/L	14 to 67	33	285[d]	202
Fluoride	mg/L	0.005 to 0.05	0.05	0.710	0.49
Nitrate as N	mg/L	0.09 to 0.76	0.6	18[d]	12
Phosphate	mg/L	No data available	No data available	4.8	4.8 (does not include BBID data)
Alkalinity as $CaCO_3$	mg/L	29 to 95	57	260	193
Arsenic	mg/L	0.001 to 0.003	0.0017	<0.005	0.0039
Barium	µg/L	151	151	12	58
Beryllium	µg/L	<1.0	<1.0	<10	7
Boron	mg/L	0.002 to 0.4	0.14	1	0.716
Cadmium	µg/L	<1.0	<1.0	<2	1.67
Chromium	mg/L	0.0025 to 0.05	0.004	0.043	0.030
Copper	mg/L	0.002 to 0.01	0.004	0.0058	0.005
Lead	mg/L	0.0005 to 0.0025	0.0024	0.0065	0.005
Mercury	µg/L	<1.0	<1.0	0.0111	0.337
Nickel	µg/L	<10	<10	5.1	7
Silver	µg/L	<10	<10	<2	5
Selenium	µg/L	0.0005 to 0.0025	0.0006	<1	0.67
Thallium	µg/L	<1.0	<1.0	84	57
Zinc	mg/L	0.0025 to 0.009	0.007	0.01	0.009
TOC	mg/L	3 to 7	4.06	No data available	4.06(BBID data only)
Turbidity (NTU)	mg/L	3 to 23	12	2[e]	5
Silica, dissolved	mg/L	No data available	No data available	30[d]	30 (does not include BBID data)
TDS	mg/L	97 to 295	174	825	610
TSS	mg/L	No data available	No data available	5[e]	5 (does not include BBID data)
Settleable solids	mL/L	No data available	No data available	<0.1	< 0.1 (does not include BBID data)
BOD	mg/L	No data available	No data available	5[e]	5 (does not include BBID data)
Oil and grease	mg/L	No data available	No data available	<5	<5 (does not include BBID data)
Hardness as $CaCO_3$	mg/L	46	46	230	169

TABLE 7-3
Estimated BBID Raw Water Quality, DDSD Recycled Water Quality, and EAEC Cooling Tower Makeup Water Quality in Year 20

		Range of Water Quality Data			
		BBID Raw Water [a,b]			
Parameter	Units	Range	Mean	DDSD Recycled Water	Estimated EAEC Water Quality in Year 20 [c]

[a] Data are based on monthly grab sample data collected from the Intake Channel during 1995, 1996, and 1997 (through August). (ECO:LOGIC, January 1998). Information supplemented with grab sample data collected from Intake Channel in July 1999 (Precision Enviro-Tech Samples, July 1999)
[b] The water quality of BBID's supplies is variable, depending on the time of year and background hydrology of the Delta (i.e., dry versus wet years).
[c] In instances where ranges of data exist for water quality concentrations, the arithmetic average value was used to determine the concentration for blending purposes.
[d] Where DDSD data was unavailable, an estimate of the constituent value was made based on typical treated wastewater quality in the vicinity of the project.
[e] Predicted value based on proposed filtration system at DDSD.

7.1.4 Cooling Tower Circulating Water Quality

As described in Section 2, incoming raw or recycled water will be used as makeup to the project's cooling tower. The estimated water quality of recirculating cooling tower water is dependent on the quality of incoming water. Recirculating water quality has been estimated at steady-state conditions for each of six water balances representing various incoming water quality(see Section 2.0). Cooling tower water quality will generally be at its highest concentration of constituents when 100 percent recycled water service is initiated. Because the project is based on zero discharge, there would be no impacts from direct discharge of the circulating water. The impacts of circulating water to air quality (e.g., PM_{10}) are discussed in Section 8.1 and the potential impacts of cooling tower drift (primarily from TDS) on biological resources are discussed in Section 8.2. A table of circulating water quality is provided in Section 8.14. Since there is no discharge of circulating water from the site, a more extensive discussion of circulating water quality is not included here.

7.1.5 Zero-Discharge System Water Quality

As described in Section 2.0, an onsite zero-liquid discharge treatment system will treat cooling tower blowdown to separate pure water from the salts that are dissolved in the incoming source water. At the end of that treatment process, a concentrated stream of dissolved solids (brine) will be discharged into evaporation ponds where the remaining water will be evaporated, leaving the solids in the ponds. The quality of the concentrated brine based on a potential use of 100 percent recycled water (worst case) is estimated in Table 8.14-3.

7.1.6 Alternatives

Several possible alternatives for the BBID raw water pipeline route and the MHCSD WWTP recycled water pipeline route were evaluated. These alternatives are described in detail below.

7.1.6.1 BBID Raw Water Conveyance Alternatives

Four alternative routes were considered to provide water supply to the project from BBID's Canal 45. These were Alternatives 3a, 3b, 3d, and 3e. As noted later in this section, Alternative 3c was considered early in project scoping and discounted as having potentially more environmental impacts than the other alternatives. Figure 2.1-1 shows the BBID raw water conveyance alternatives.

All alternatives except Alternative 3b involve installing a pump station and pipeline from the existing BBID Canal 45 in the location of the Bruns Road crossing to convey water to the EAEC. Alternative 3b involves using the existing canal facilities up to a point where Canal 70 crosses Mountain House Road, at which point a pump station and pipeline would be used to convey water to the EAEC.

BBID's normal maintenance schedule for the canals requires them to be shut down from November through March for cleaning of aquatic weeds, other vegetation, and periodic canal bank reshaping. To facilitate a more continuous operation of BBID's facilities, concrete canal lining and a water control structure will be used on those existing canals that are incorporated into the water supply features for the EAEC. By installing canal lining, the maintenance requirements will be significantly reduced in these sections. The water control gate would allow dewatering of the downstream BBID facilities.

For Alternatives 3a, 3d, and 3e, the existing Canal 45 would be lined between BBID's existing pumps on the California Aqueduct and the new pump installation to be located on the southeast side of the intersection of Bruns Road and Canal 45. In addition, at this location a water level control gate would be constructed in Canal 45 immediately downstream of the new pump station. This structure would consist of a radial gate structure constructed to maintain a water surface on the upstream side of the structure. The pump station at the Bruns Road location would pump into a 24-inch buried pipeline to convey water to the EAEC.

For Alternative 3b, the project would use the existing Canal 45 and Canal 70 to convey water to a new pump station at Mountain House Road and Canal 70. In this alternative, all of Canals 45 and 70 between the California Aqueduct and the pump station would be lined to facilitate winter operations. Similar to the other three alternatives, a water control structure would be constructed immediately downstream of the Canal 70 intersection with Mountain House Road to allow winter dewatering of the downstream canal.

The following sections provide site-specific descriptions of each alternative route.

Alternative 3a. This alternative involves installing a pump station in Canal 45 at the southeast corner of the intersection of Canal 45 and Bruns Road. Approximately 2.6 miles of 24-inch pipeline would be installed north along Bruns Road and then southeast along Byron Bethany Road to the project site.

This alternative would require longitudinal encroachment permits within Alameda County and Contra Costa County ROWs. The route would also require private property easements along portions of Byron Bethany Road or open-cut construction methods in the roadway to avoid existing utility lines in the ROW.

The pipeline would cross a high-pressure oil pipeline along Byron Bethany Road and the large box culverts that route the Delta-Mendota Canal water under Byron Bethany Road. The tops of these box culverts are approximately 12 feet below ground surface. Therefore, the pipeline could be installed over the culverts, avoiding the need for directional drilling under the canal. The crossing of the Delta-Mendota Canal would require encroachment permits from USBR and the San Luis Delta-Mendota Water Authority. In addition, the route would cross Mountain House Road using open-cut construction methods.

Annual pumping energy requirements would be approximately the same as for Alternative 3e (discussed later in this section).

Alternative 3b. This alternative would use the existing Canal 45 and Canal 70 and associated existing pump stations to transport water from the California Aqueduct to the intersection with Mountain House Road. At the intersection of Canal 70 and Mountain House Road, a pump station and a 3,000-foot (0.6 mile)-long pipeline would be installed to convey the water across and then along Mountain House Road north to the EAEC. The total length of the alternative, including the length of the canals, would be approximately 3.6 miles.

An Alameda County encroachment permit would be needed to construct the project facilities located in the Mountain House Road ROW. The pump station would be similar to the other alternatives. Pumping energy would be about 10 percent less than for Alternative 3e.

To facilitate the operation of this alternative in the winter, it is likely that the canals would be lined to the pump station located at Mountain House Road. Areas adjacent to the canals currently show wetland characteristics. These areas would be potentially subject to U.S. Army Corps of Engineers and/or CDFG permits if any construction disturbance affected these areas. Any alteration of the canal (including lining) would be planned within BBID's ROW.

The two lift stations along the canals that assist in transporting water downstream would need to be in operation year-round with implementation of this alternative, requiring additional energy. In addition, planned outages of these pump stations for periodic maintenance would need to be coordinated with the EAEC needs.

Alternative 3c. Alternative 3c was considered early in project scoping and discounted as having potentially more environmental impacts than the alternatives presented here.

Alternative 3d. Similar to Alternative 3a and Alternative 3e, this alternative would require lining Canal 45 from the California Aqueduct to the new pump station at Canal 45 and Bruns Road. At this location, the water control structure would also be constructed to allow downstream dewatering of the BBID facilities.

Alternative 3d would require 2.4 miles of 24-inch pipeline between the pump station and the generating facility. The pipeline would be installed south along Bruns Road for approximately 0.5 mile, then along an existing gravel road (used by BBID) east to the Delta-Mendota Canal, and then north to Byron Bethany Road. The pipeline would then be installed south along Byron Bethany Road and cross Mountain House Road to reach the project site.

Similar to Alternative 3a and Alternative 3e, this alternative would require longitudinal encroachment permits in Alameda County and Contra Costa County ROWs; some of the ROW along the gravel road would need to be obtained from private landowners. Crossing the Delta-Mendota Canal would require encroachment permits from USBR and the San Luis Delta-Mendota Water Authority.

The alternative would require open-cutting across Mountain House Road. The pipeline would cross one high-pressure oil pipeline, Canal 45 along the gravel road, and large box culverts that route the Delta-Mendota Canal water under Byron Bethany Road.

Energy requirements would be approximately the same as for Alternative 3e.

Alternative 3e (Preferred Alternative). Alternative 3e is similar to the route associated with Alternative 3d, with the exception that Alternative 3e would proceed along the gravel road and cross under the Delta-Mendota Canal directly west of the project site. From this location, the pipeline would proceed directly to the EAEC. The total length of the pipeline for this alternative is 2.1 miles.

The crossing of the Delta-Mendota Canal would be done using horizontal directional drilling methods. This alternative would not cross the high-pressure oil pipeline along Byron Bethany Road and the large box culverts that route the Delta-Mendota Canal water under Byron Bethany Road.

As noted previously, the annual energy use for this preferred alternative is approximately 600,000 kWh/yr.

7.1.6.2 Conveyance of MHCSD WWTP Recycled Water Alternatives

Two alternatives to convey water from the MHCSD WWTP to the project are presented in this section. Both alternatives include installing a 24-inch pipeline and a pump station adjacent to the future MHCSD WWTP. The pump station for either alternative would be as described above in Section 7.1.2, Recycled Water Supply. The availability of recycled water from the MHCSD WWTP for these alternatives will be based on further discussions between BBID and MHCSD. As the area's water purveyor, BBID would be responsible for distribution of the recycled water.

The pipeline in each alternative would cross two existing creek beds and the Union Pacific Railroad (UPRR) along Byron Bethany Road where there are high-pressure oil pipelines. Each alternative would require trenchless construction methods for portions of the alignment. The pipelines could also be used to carry recycled water to customers other than EAEC in the BBID service area. The use of that water, and the facilities needed to pump it, would be subject to agreements between BBID, EAEC and possibly other BBID customers and would involve cost sharing agreements between BBID and MHCSD as well.

Alternative 4a. This alternative would be designed to provide a supply of at least 350 AF per month directly to the project. The pump station would be sized as discussed above in Section 7.1.2, Recycled Water Supply. This alternative would include approximately 4.3 miles of 24-inch pipeline installed from the site of the future MHCSD WWTP, west along Bethany Road, northwest along Byron Bethany Road, and west on Kelso Road to the project site. (The alignment along Kelso Road would be in accordance with the final configuration of Kelso Road, as determined by MHCSD.) This alternative will require longitudinal encroachment permits in Alameda County and San Joaquin County ROWs.

Alternative 4b (Preferred Alternative). Similar to Alternative 4a, the preferred alternative would provide a supply of 350 AF per month directly to the project site. The pump station would be sized as discussed above in Section 7.1.2, Recycled Water Supply. This alternative would include approximately 4.6 miles of 24-inch pipeline installed from the site of the future MHCSD wastewater treatment plant, west along Bethany Road, and then northwest along Byron Bethany Road to the project site. This alternative will also require longitudinal encroachment permits in Alameda County and San Joaquin County ROWs.

7.1.6.3 Selection Criteria and Alternatives Analysis

The proposed and alternative pipeline routes were evaluated based on institutional factors (e.g., ease of obtaining ROW, public agency support, required permits, etc.); engineering/ construction feasibility; length of the pipeline/cost; and potential environmental impacts. Engineering/construction feasibility is an assessment of whether the pipeline can be physically placed along a given route. Length of pipeline is important because pressure drop, cost, and potential environmental impacts are typically functions of the pipeline length. Table 7-4 provides a summary of how each alternative rates against the selection criteria.

TABLE 7-4
Comparison Summary of Alternatives

	BBID Raw Water Conveyance Alternatives				MHCSD WWTP Recycled Water Conveyance Alternatives	
Criteria	**3a**	**3b**	**3d**	**3e**	**4a**	**4b**
Institutional Factors	◐	●	◐	◐	◐	◐
Engineering/ Construction Feasibility	◌	◌	◌	◐	◌	◌
Length of Pipeline	◌	◌	◌	◌	◌	◌
Environmental Factors	◌	●	◌	◌	◌	◌

Legend

●	Potential for impacts is SIGNIFICANT
◐	Potential for impacts is LESS THAN SIGNIFICANT but poses SLIGHTLY GREATER challenges than other alternatives
◌	Potential for impacts is LESS THAN SIGNIFICANT

Institutional Factors. For each of the BBID water conveyance alternatives, county encroachment permits would be required. Alternatives 3a, 3d, and 3e would require encroachment permits from USBR and the San Luis Delta-Mendota Water Authority when crossing the Delta-Mendota Canal. Preliminary meetings with USBR and the San Luis Delta-Mendota Water Authority indicate that all these routes and contemplated canal crossings are feasible. Alternatives 3d and 3e would require a private easement along the gravel road; Alternative 3a could also require private easements if open-cutting the roadways is not a favorable option. A Contra Costa County building permit would also be needed to build the pump station for Alternatives 3a, 3d, and 3e. An Alameda County building permit would be needed to build the pump station for Alternative 3b. For Alternative 3b, lining and widening Canal 70 could be necessary to install the pump station, potentially disturbing areas adjacent to the canals that show wetland characteristics from canal seepage. These areas could be subject to U.S. Army Corps of Engineers and/or CDFG permits.

As with the BBID water conveyance alternatives, both of the MHCSD WWTP water conveyance alternatives would require county encroachment permits. The MHCSD WWTP water conveyance alternatives would also require UPRR encroachment permits. Although the routes would cross two existing creek beds, trenchless technology may be employed at the creek beds to avoid biological impacts and the need to acquire U.S. Army Corps of Engineers and/or CDFG permits. Consultation, however, with both agencies would be conducted. Alternative 4a would require consultation with the MHCSD to determine the final configuration of Kelso Road.

Engineering/Construction Feasibility. Alternatives 3d and 3e would cross one high-pressure pipeline and Canal 45. Alternative 3d would also cross over the box culverts at the Delta-Mendota Canal along Byron Bethany Road. Alternative 3e would require directional drilling under the Delta-Mendota Canal. Alternative 3a would involve similar construction methods as Alternative 3d; however, Alternative 3a would involve additional roadway cutting unless private easements are acquired.

Both of the MHCSD WWTP alternatives would generally follow the same route and would involve similar construction methods.

Length of Pipeline. The longest BBID raw water pipeline is associated with Alternative 3a, which is 2.6 miles long. Apart from Alternative 3b, the preferred route (Alternative 3e) is the shortest at 2.1 miles long. Alternative 3d is 2.4 miles long. The pipeline associated with Alternative 3b would be relatively short, but would potentially require additional canal improvements.

Alternative 4b is the preferred alternative at 4.6 miles long. Although Alternative 4a is shorter (4.3 miles) the pipeline route that follows Byron Bethany Road would provide for long-term flexibility to BBID in delivering recycled water to other users in future.

Environmental Factors. Each of the pipeline routes pass primarily through agricultural land or land that is already disturbed, either by a roadway or a railway. Potential environmental impacts from pipeline construction would be to biological, cultural/paleontological, or traffic and transportation resources. The proposed routes were surveyed for biological and cultural/paleontological impacts. Potential impacts from the proposed routes are discussed in other sections of this document, and potential impacts from the alternative routes are presented in Section 9.0, Alternatives. The routes that involve creek bed crossings could result in more significant biological and hydrological resources impacts; using trenchless technology, however, would mitigate these impacts. Alternative 3b could involve the widening or lining of Canals 45 and 70, potentially resulting in significant biological and hydrological resources impacts. Similarly, the routes that involve construction along Byron Bethany Road could result in significant traffic impacts because of the traffic volumes on that roadway; acquiring private easements along the road, however, would avoid these impacts.

7.1.7 Construction Practices

Given the diameter of the proposed pipelines, welded steel, ductile iron, concrete cylinder pipe with pretensioned steel, high-density polyethylene, or PVC pipe could be used. Construction of the pipelines is anticipated to be accomplished using conventional pipelaying methods—open cut construction wherever possible, with "trenchless technologies," such as bore and jack, microtunnelling, or directional drilling, possibly used for crossing specific features such as rivers and creeks, highways, railroads, or other major infrastructure.

Paving equipment would be used to replace the pavement removed as part of the pipeline construction. The construction labor needed to complete this project is discussed in Section 8.8, Socioeconomics.

The width of the construction work area will be approximately as follows:

- Diameter of pipe – 24 inches
- Width of trench – 4 feet
- Width of permanent easement width – 15 to 20 feet
- Width of typical construction easement – 25 to 50 feet (maximum width of "impact" area could be 70 feet.)

Construction of the pipelines is expected to begin about 6 to 8 months following the start of construction of the project. The first several months would be used to acquire materials and to mobilize for construction. Total construction time is expected to be 6 to 8 months.

7.2 Domestic Use Water

Since a portion of the water conveyed to EAEC for cooling could be recycled water, it would not be suitable for domestic use. The domestic water demand is estimated to be approximately 1.9 AF per year for up to 40 employees maximum. To meet this small demand, either a domestic water supply pipeline would be constructed to supply water from the adjacent federal facility or a well and treatment system would be installed onsite to be used exclusively for domestic uses. The 1995 BBID Groundwater Management Plan (management plan) reported that an established groundwater monitoring program is not in place in the vicinity of the project site; it is, therefore, difficult to assess the existing groundwater quality of the area. The management plan, however, indicated that water quality in the area is poor. Total dissolved solids (TDS) exceed 1,500 mg/L, chlorides exceed 250 mg/L, and the groundwater is high in boron. The management plan does not specify the depth to which these data correspond. The management plan reports that most domestic wells tap the shallower fan deposits (less than 200 feet) and the better-producing wells tap the deeper Tulare deposit sands (200 to 600 feet). Most homes in the area are reported to use bottled water for drinking.

The required production rate for the onsite well would be supplied by one four-inch submersible pump in a six-inch PVC well with a pressurized water storage tank. The pump would automatically cycle on and off to maintain pressure in this tank. The maximum production for the pump would be at a rate of approximately 30 gallons per minute for

30 minutes. Otherwise, the pump would be shut off. It is unlikely that this low pumping rate would affect the production capacity or water quality of other wells in the vicinity of the project well. The nearest existing well is a private domestic well located approximately one-quarter mile southwest of the project site.

The total depth of the well would be over 300 feet with a 50-foot screen; depth to water is approximately 4 feet. The well would be located upgradient from the plant's septic system. Exploratory drilling would need to be conducted onsite because little hydrogeologic data exists for the area. A test well would be drilled and lithologically sampled to a depth of 500 feet. An aquifer test would be conducted at the test well to determine the local aquifer properties and estimate the well's potential yield. The well would also be sampled to determine the type of treatment system necessary to bring the well water to drinking water quality. Based on the results of these field tests, the final well design would be developed.

As an alternative to using onsite groundwater for domestic purposes, obtaining domestic water from the local domestic water treatment plant which serves Western and the other federal and state facilities in the area will be pursued. The tank for this facility is located approximately 1,500 feet north of Kelso Road, just west of the Delta-Mendota Canal. This option would require a 2-inch to 4-inch pipeline that would run south to Kelso Road, east on Kelso, then north on Mountain House Road to the project site.

7.3 Process Makeup Water

During average operating conditions, blowdown water from the cooling towers would be treated onsite to provide process makeup water. During peak operating conditions, a portion of the incoming raw water supply would be allocated to process makeup water. Details of the plant water cycle and process makeup water treatment are discussed in Section 2.0, Project Description.

7.4 References

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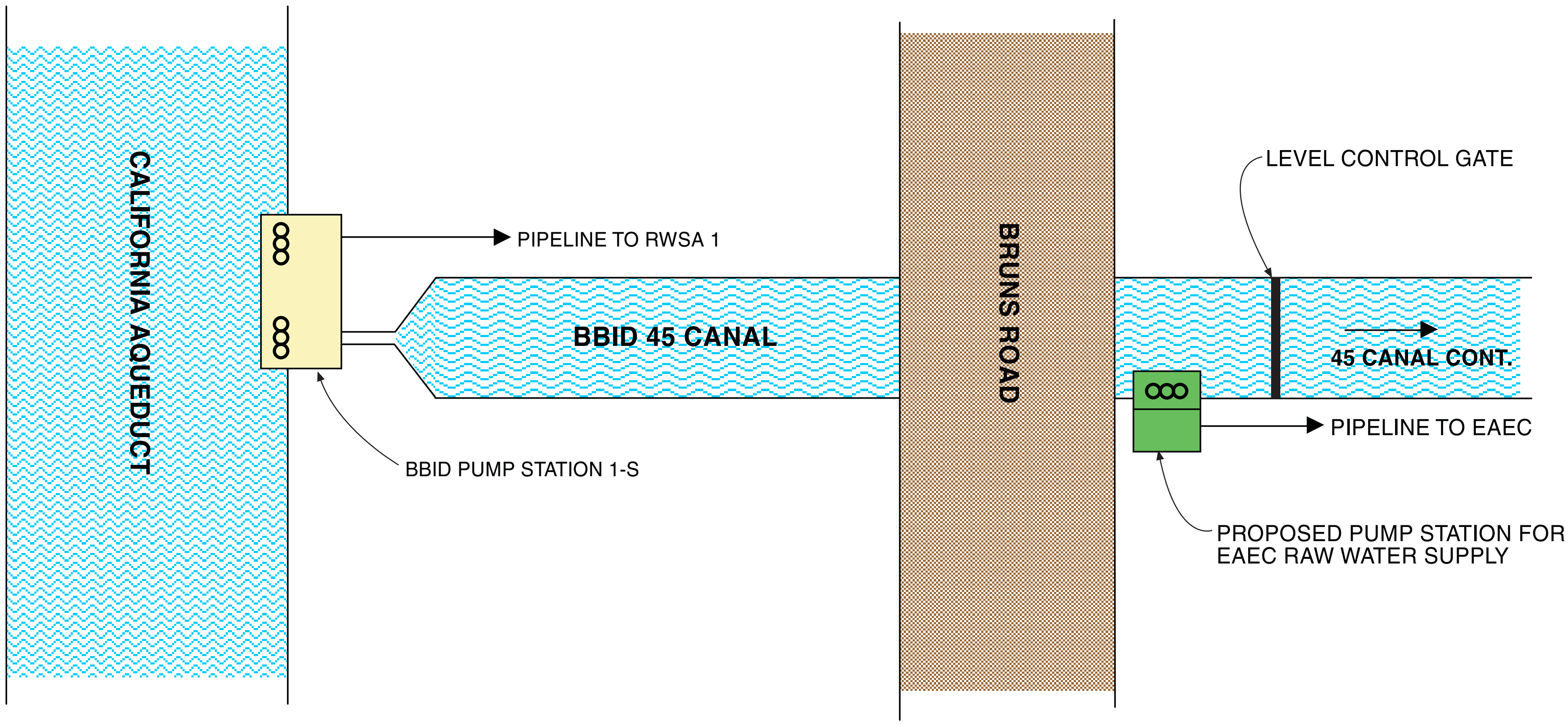

FIGURE NOT TO SCALE

FIGURE 7.1-1
SCHEMATIC LAYOUT OF PUMPING FACILITIES FOR PREFERRED RAW WATER SUPPLY COMPONENT FROM BBID
APPLICATION FOR CERTIFICATION FOR EAST ALTAMONT ENERGY CENTER

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