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9.0 ALTERNATIVES

9.1 INTRODUCTION

In this section of the application, alternatives to the proposed CGS are discussed and the results of the alternatives evaluation are described. Alternatives were considered as part of the project formulation process. Project alternatives, and specifically, evaluation of the No Project Alternative, are required by the CEC's regulations so that it can comply with CEQA requirements.

E&L Westcoast proposes to construct and commission a nominal 660 MW combined cycle power plant in Colusa County. The facility will incorporate two combustion turbines that will burn natural gas and a steam turbine driven with steam generated by HRSGs. Each combustion gas turbine and the steam turbine will be connected to one of three separate electric generators. Output of the generators will be connected to step-up transformers and then to a new PG&E switchyard. The CGS will be interconnected to PG&E's northern California transmission grid and power generated by the facility will be available to serve energy needs throughout California.

9.2 PROJECT OBJECTIVE

The initial objective for the project was to satisfy PG&E's 2004 *Long Term Facility Ownership Request for Offers* to obtain power resources. In April 2006, PG&E executed an agreement with E&L Westcoast for the purchase of the 660 MW CGS project. The current objective of the project is to design and construct the project at the proposed site and with the specified equipment to fulfill the requirements of the agreement.

9.3 ALTERNATIVES CONSIDERED

As part of the evaluation, a broad range of alternatives were considered, including:

- No Project Alternative
- Site Alternatives
- Generation Technology and Plant Configuration Alternatives
- Water Supply/Cooling System Alternatives
- Transmission Interconnection Alternatives
- Gas Supply Alternatives

Much of the alternatives evaluation for the CGS, specifically site and technology selection, was done as part of developing the response to PG&E's Request For Offer. Once the project was selected by PG&E, alternatives for the plant's cooling system and water supply were evaluated. The following sections describe the alternatives considered and summarize the results of the evaluation.

9.4 NO PROJECT ALTERNATIVE

The No Project Alternative is an alternative required by CEC's regulations. Denial of this application by the CEC would, in effect, be the No Project Alternative. Should this occur, the primary result would be the loss of 660 nominal MW of generating capacity to provide energy to the State of California.

Were the No Project Alternative to result, the following environmental changes would not occur:

- Approximately 31 acres of land would remain grassland.
- Approximately 15 acres of land would remain undisturbed from the installation of underground pipelines, transmission facilities, and access road.

- The Teresa Creek Bridge and Glenn-Colusa Canal Bridge would remain in their current condition and would not be upgraded by the project.
- The intersection of Delevan Road and McDermott Road would not be improved.
- Approximately 126 acre-feet per year of existing water would remain allocated to GCID and would not be used by Colusa County for industrial purposes.
- Colusa County would forego approximately $1.575 million to $2 million in annual tax revenue.
- Land uses, habitat values, ambient noise, landform, and visual quality of the area would remain unchanged.

The adverse consequences of the No Project Alternative include the following:

Loss of generating capacity to serve California load – The State of California is in the midst of an energy supply shortfall to meet existing and future electrical loads. Development of new energy supplies is not meeting increasing demands in the state (CEC, 2005). PG&E estimates that it will need to acquire approximately 2,200 MW of dispatchable capacity by 2010.

The supply shortfall has resulted in governmental initiatives to bring on line new generating capacity. Power plants that have recently been approved by the CEC are not expected to completely resolve the state's shortfall. The No Project Alternative would eliminate a source of 660 MW of reliable energy supply that is needed to alleviate the shortfall in generating capacity and ease the energy situation in California.

Loss of reliability – Under certain circumstances, supply shortfalls can result in planned or unplanned blackouts. During blackouts, emergency stand-by generators are used as an alternative source of power. These generators typically run on fuels (e.g., diesel) that have much higher emissions than natural gas and are much less efficient. Thus, the absence of reliable sources of power can lead to serious air quality and public health consequences.

Loss of increase in energy conversion efficiency – As a gas turbine combined cycle generating facility, the proposed CGS would be one of the most efficient generating facilities in the state. Its highly efficient energy conversion capability (natural gas to electricity) would produce less air emissions and other environmental effects per kilowatt hour of energy produced than most of the power plants that are currently operating and those that are being constructed on an expedited basis to provide immediate power to the state. When in operation, the CGS would incrementally increase the state's average energy conversion efficiency. Under the No Project Alternative, the increase in efficiency would not be realized because less efficient older and peaking plants would run more hours of the year.

9.5 SITE ALTERNATIVES

As a basis for selecting the site, the following criteria were used:

- **Proximity to infrastructure** – The site must be located in close proximity to high-voltage transmission lines, a high-pressure major gas transmission system, and potential water source(s).

- **Environmental viability** – The site should have few or no environmentally sensitive areas and should allow development with minimal environmental impacts.

- **Minimal impact on surrounding community** – The site should enable the development of a power plant with minimal negative impact on the surrounding community.

- **Compliance with Laws, Ordinances, Regulations, and Standards** – The site should provide opportunity for compliance with all LORS.

Two sites were analyzed as alternative sites that would feasibly meet most of the above criteria.

The first alternative site is located approximately 5 miles south of Williams and 5 miles west of I-5 directly adjacent to PG&E's Cortina substation. This alternative site fits the project's basic criteria, given its proximity to both major gas and power transmission infrastructure. PG&E's 230 kV lines that interconnect with the Cortina substation would provide ample take-away capacity for a 660 MW power plant, and there is adequate capacity on PG&E's 400 and 401 gas mains. Based on initial biological assessments, constructing the power plant on this site does not appear to have the potential to cause any significant biological impacts. However, it is anticipated that existing farmland would need to be taken out of production to create a footprint large enough for the project. To obtain site control and lateral easements, negotiations would be required with several landowners. The site is located within 1.7 miles of one residence and within 2 miles of numerous others. Like the preferred site, the parcels are not currently zoned for industrial use or designated for industrial use in the Colusa County General Plan. Additionally, this site did not appear to present construction issues that were significantly different from those at the preferred site.

It was concluded that this site did not avoid the current existing land use designation conflict, that it brought no particular advantage over the preferred site, and in fact, had certain disadvantages such as multiple owners and existing agricultural production on site. As a result, further investigation was not pursued.

The second alternative site that was evaluated is situated on the southern end of the Holthouse Ranch. Located just south of the ranch headquarters along the eastern boundary of the property, this site would provide many of the same benefits as the CGS project site. There is adequate transmission and gas infrastructure, and only one landowner would need to be negotiated with for both site control and lateral easements. As with the preferred site, this site appears to present no unique obstacles to construction. However, the potential for significant biological impacts exists at this location due to the presence of wetlands and vernal pools. It was deemed that these areas would not only be affected by the power block and switchyard footprints, but by the transmission interconnection and construction laydown areas as well.

Due to the potential biological impacts associated with this location, the preferred site was selected over this alternative site.

The preferred location for the CGS is superior to the alternative sites because linear interconnections are minimized, impacts to sensitive biological resources can be avoided and minimized, and the owner of the Holthouse Ranch is interested in making this portion of the ranch available for power plant development.

9.6 GENERATION TECHNOLOGY AND CONFIGURATION ALTERNATIVES

After construction and commissioning, E&L Westcoast would transfer ownership and operation of the plant to PG&E to supply energy to the California market. To meet PG&E's resource needs, both peaking and shaping generation are needed to fill in the gaps between projected production from existing generation and contracted resources and projected demand. Facilities must be flexible and highly reliable. PG&E's requirements include the following:

- Meet all air emission permit limits at startup, shutdown, and during all operating loads;
- Provide Automatic Generation Control (AGC) to comply with the California Independent System Operator's (CAISO's) requirements;

- Meet minimum downtimes and minimum ramp rates for shaping generation units; and
- Have a design life of 30 years.

9.6.1 Generation Technology Alternatives

In preparing the response to the PG&E Request For Offers, various generation technologies were evaluated. These included:

- Fossil fueled/steam electric (gas turbine, conventional boiler fueled by natural gas, distillate or coal)
- Nuclear
- Solar
- Biomass
- Hydroelectric
- Wind
- Geothermal

Fossil – An evaluation of fossil generation technology necessarily involves consideration of both generation technology and fuel alternatives. Technology alternatives include combustion turbine-generation (both simple and combined cycle) and conventional boilers. Fuel alternatives include natural gas, coal, and distillate. Of the fuel alternatives, natural gas, with its lower sulfur dioxide and particulate emissions is the preferable fossil fuel for use in California. Local air district air permitting regulations prohibit the use of coal. Distillate fuels are also discouraged for units that are designed to run more than a limited number of hours per year.

Nuclear – Nuclear generation was not considered to be a feasible technology because of the associated long lead time and high initial capital cost. No new nuclear power plants have been constructed in California since Diablo Canyon and little of the engineering and construction industry capacity required for this technology is available at the current time. Furthermore, it would take more than 5 years to permit such a facility, and a similar amount of time for construction. In addition, the State of California has a moratorium on the construction of any new nuclear facilities until a licensed permanent waste disposal facility is in operation.

Solar – Solar technology is most appropriate as a demand reduction technology. When operated to supply individual energy users, it reduces the amount of energy required from the electrical grid. However, it cannot be controlled by a central system operation that increases/decreases facility output in response to systemwide energy demand. Solar thermal technologies do not provide the continuous reliable power that is one of the key objectives for the CGS. Solar facilities use large tracts of land; parabolic troughs typically require approximately 4 to 5 acres per megawatt output (CEC, 1996). In order to produce 660 MW, approximately 2,640 to 3,300 acres of land would be needed for a parabolic trough system. This would be more than 26 times the amount of land to be used by the proposed project. Therefore, this technology was not considered to be a feasible technology for the CGS.

Biomass – Biomass technology is similar to conventional boiler facilities but is generally limited to a much smaller project size (typically 10 to 25 MW) and has lower thermal conversion efficiency. In order to produce 660 MW, more than 20 biomass units would be required. Emissions from biomass projects are typically greater than from gas-fired projects. The ability to meet air quality requirements, especially with this many units, may not be achievable. Because of size and efficiency limitation, biomass technology was not selected.

Hydroelectric – Hydroelectric technology was determined to be infeasible because of the extensive time such a project would require and significant impacts typically associated with hydroelectric development.

A significant obstacle to development of a privately initiated hydroelectric facility is acquisition of land suitable for this technology. In addition, the environmental review and approval process for a new hydroelectric project of similar scale to the proposed CGS could take more than 5 years. Construction could take several more years. Such a project would not come on line for 8 or more years. Such long lead times and the uncertainty of the licensing process make this technology infeasible as a technology alternative.

Wind – Wind energy was not considered to be a feasible technology for several reasons. Due to the natural intermittent availability of wind resources, wind energy is not always available. This technology is characterized by a low average capacity factor and therefore does not provide a source of reliable energy. It also requires significant land area and the installation of a large number of individual machines to form a significant amount of generating capacity in aggregate. Wind generation farms generally require large tracts of land; approximately 17 acres of land are needed to produce 1 megawatt of electricity (CEC, 1996). In order to produce 660 MW, approximately 11,200 acres of land would be required. This would be more than 100 times the amount of land used by the proposed project and more than two times the amount of land held by the Holthouse Ranch. With these characteristics, wind energy was rejected as a feasible technology alternative.

Geothermal – Geothermal technology was determined to be infeasible because it is limited to specific geologic conditions that are present only in certain areas of California.

9.6.2 Other Plant Configuration

In addition to generation technology alternatives, alternative machine types and sizes were considered. However, PG&E requested that GE Frame 7FA turbines be used for the project because of the equipment's proven history for reliability. The following plant configurations and maximum output alternatives were evaluated:

- 1,000 MW Combined Cycle Plant – A plant of this size would have employed two 2 × 1 gas/steam turbine configurations.
- 850 MW Combined Cycle Plant – This plant configuration would have consisted of a 3 × 1 gas/steam turbine combination.
- 660 MW Combined Cycle Plant – This plant, which was ultimately chosen, uses a 2 × 1 gas/steam turbine configuration, with additional peaking output.
- 520 MW Simple Cycle Plant – A simple cycle configuration of 3 × 0 gas/steam turbine configuration was evaluated.

During the evaluation stage of the development process, both the 1,000 MW and 850 MW plants were ruled out as viable options due to transmission constraints. The simple cycle plant was not chosen due to less efficient fuel use and other economic considerations. The 520 MW simple cycle plant is less efficient and did not meet PG&E's requirements to satisfy needed capacity and operational flexibility.

9.7 WATER SUPPLY/COOLING SYSTEM ALTERNATIVES

The CEC implements state water policy to minimize the use of fresh water, promote alternative cooling technologies, and minimize or avoid degradation of the quality of the state's water resources. The state's water policy, adopted by the SWRCB, is specified in Resolution 75-58. The Commission's 2003 Integrated Energy Policy Report (IEPR) provides that "...the Commission will approve use of fresh water for cooling purposes…only where alternative water supply sources and alternative cooling technologies are shown to be 'environmentally undesirable' or 'economically unsound.'" Economically unsound is defined as economically or otherwise infeasible. Feasible means capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, legal, social, and technological factors.

The CEC's regulations require the Applicant to provide information on the source of water supply, the rationale for its selection, and whether fresh water is to be used for cooling purposes, to discuss all other potential sources and why they were not considered feasible.

9.7.1 Alternative Plant Cooling System Considerations

The consideration of power plant water supply includes consideration of water requirements to meet process needs and the availability of alternative water supplies. Power plant water requirements, other than for general maintenance and personnel needs, are related to cooling and to the steam cycle. All of the generation technologies that include a steam cycle (generation of steam to drive a steam turbine generator) require water for steam generation. A heat transfer medium is also required to condense the low-quality steam at the end of the cycle. Two methods of steam condensing are typically used: circulating cooling water through a condenser, and direct condensation of the steam in an air-cooled condenser. The use of a circulating cooling water system entails the use of cooling towers, which can have a significant impact on plant water requirements.

Cooling system alternatives that are available range from wet cooling towers to air cooled condensers (dry system). An intermediate alternative is a hybrid system that incorporates a portion of both the wet and dry technology. Because wet towers and an air cooled condenser system represent the extremes in water requirements, these two cooling system alternatives were evaluated. A comparison of the general features of these two systems shows:

- Installed costs for the air cooled condenser are significantly more than for a wet cooling tower.
- When using an air cooled condenser, plant output is less than when using a wet cooling tower.
- Water requirements for the air cooled condenser can be on the order of 2,500 acre-feet per year less than the wet cooling tower for a 500 MW plant (CEC, 2006).

The use of wet cooling technology was considered as an alternative to dry cooling technology. The benefits of using wet cooling technology would include the following:

- Higher efficiency (less natural gas consumption).
- Less air emissions.
- Less visual impacts.

When comparing fuel consumption of dry versus wet cooling technologies, it was determined that natural gas savings alone using wet cooling could have supplied energy for a significant number of households. Wet cooled technology would also have produced less NO_X, VOC, and CO_2 emissions than dry cooled technology. In addition, when considering visual impacts, wet cooling would have included a 50-foot-tall wet cooling tower rather than a 144-foot-tall air cooled condenser.

Water consumption requirements for wet cooling, however, are significantly higher than dry cooling. Anticipated water use for wet cooling was estimated at 3,000 to 3,500 acre-feet per year rather than the 126 acre-feet per year for dry cooling. Although it was determined that there was an abundant water supply in the region and water consumption requirements could be met for wet cooling, dry cooling technology was chosen for the proposed project based on the CEC policy set forth in the 2003 IEPR.

9.7.2 Alternative Water Supply Considerations

The Applicant evaluated several different alternative water supply and conservation options as part of the project. Based on the annual water requirements of approximately 126 acre-feet per year, which is less than 0.03 percent of the amount of water transported and delivered to Colusa County via both the Tehama-Colusa Canal and the Glenn-Colusa Canal, the use of GCID water is preferred as the primary water supply option for the project. Selection of this source is based on the following:

- Both the Tehama-Colusa Canal and Glenn-Colusa Canal are located near the site. Therefore, offsite linear facilities would not be extensive and no new interconnections would be required.
- GCID has senior water rights, so that supply is not curtailed more than 25 percent.
- Water transfers can be made through Colusa County because the County is a Central Valley Project contractor.
- GCID has an existing wheeling agreement with Tehama-Colusa Canal Authority (TCCA) that allows water supplied by GCID to be conveyed via the Tehama-Colusa Canal to the site vicinity.
- The water supply and quality meets the requirements for the project.
- A more than adequate water supply from GCID and robust storage capacity are available at the project site.

Other potential sources of water, as listed in SWRCB Resolution 75-58, were considered but deemed to be infeasible as summarized below.

Alternative 1: Ocean Water

Ocean water is not considered a feasible alternative because this water source is not locally available.

Alternative 2: Brackish Water from Irrigation Return Flow or Groundwater

Irrigation return flow is considered infeasible due to the cost of infrastructure that would be required to deliver the water to the project site and the unreliability of the flows.

GCID operates eleven drains within its system. These drains receive irrigation return flow which consists primarily of water from rice fields, as well as from row crops, orchard, or pasture lands. GCID allows fields to release water into its system in accordance with established polices and rules (e.g., herbicides cannot be released into the drain system). Information on the eleven drains is summarized in Table 8.14-14.

The use of irrigation return flow from the GCID drains is considered impracticable for the following reasons:

- An extensive and costly infrastructure system would be required to deliver the water from the drain to the site. The three closest drains are located between 7 and 10 miles east of the site and are located east of I-5. Pipelines would need to be constructed within the existing road rights-of-way; therefore, the length of the pipeline would be considerably longer than the direct-line distance between the site and the drain. The pipeline routes would cross several creeks and canals/ditches. A pump station would be required because all of the drains are located at elevations lower than the site. The approximate elevations of the three closest drains are between 60 and 70 feet above msl, while the site is at approximately elevation 183 feet above msl.

- The drains provide an unreliable source of water. The amount of water that is available at each drain depends on how the fields are operated, which depends on the crop, climate, etc. Based on data from GCID for the period 1996 through 2005, outflow at the eleven drains is highly variable throughout the year. Typically there is no outflow during February and March. There is no sustained minimum outflow at any of the drains during the remainder of the year.
- As a result of increased water conservation measures by upstream users, including more efficient irrigation practices and conversion to more water-efficient crops, irrigation return flows have become an increasingly unreliable source of water (USBR, 2005).
- The irrigation return flow may require treatment for use at the plant. Limited water quality data are available for the return flows, but based on the nature of the water and electric conductivity data, the water from these drains would be expected to have elevated amounts of salts and minerals.

Limited information is available regarding the use of poorer quality groundwater from deeper zones in the vicinity of the project. The base of the fresh water occurs about 400 feet below msl at the site (DWR, 2003), or about 550 to 600 feet below the site. The limited data available indicate the deeper strata may be largely non–water-bearing. Few wells have been drilled to these depths. An exploratory well was drilled on the west side of the valley near Willows in the last few years to a depth of about 1,000 feet. No significant water-producing materials were encountered below a depth of about 80 feet (Staton, 2006). While it is conceivable that a water supply could be developed from those deeper materials, determining whether that supply exists could entail substantial expense in drilling exploratory wells to find strata that might yield significant amounts of water to wells. Furthermore, even if promising water-bearing strata were identified, substantial uncertainties would remain as to the sources of recharge for those strata, and the long-term viability of production from such zones. Therefore, use of poorer quality groundwater from deeper zones is considered infeasible.

Alternative 3: Municipal Wastewater

The use of reclaimed municipal wastewater for power plant cooling at the CGS has been determined to be infeasible, primarily because the site is located in a rural area. Factors that make this source infeasible include: (1) the site is not within the service area of any sanitation district; (2) the closest wastewater treatment plant (WWTP) does not produce reclaimed water and even if it did it does not process sufficient quantities of wastewater; and (3) the next closest WWTPs are more than 10 miles away from the site and extensive infrastructure would be required to deliver reclaimed water, if even available, to the site.

The CGS would require a maximum flow of approximately 190,000 gallons per day (gpd) (132 gallons per minute [gpm]) of water. The nearest WWTP to the CGS site is the Maxwell Public Utility District WWTP, approximately 5 miles southeast of the site. This plant has a design capacity of 0.2 million gallons per day (mgd) (139 gpm) and processes approximately 0.14 mgd (97 gpm) on average. As of 2006, the plant served approximately 800 to 900 residents, with approximately 414 sewer connections (Colusa LAFCO, 2006). The plant currently does not have the facilities to provide reclaimed water. Even if the plant did produce reclaimed water and assuming a conservative 90 percent recovery rate, the amount of reclaimed water would not be adequate to supply the plant.

The next closest plants are in Willows and Williams, which are located approximately 12 miles north and approximately 15 miles south of the site, respectively. The Willows WWTP has a design capacity of 2.62 mgd (1,819 gpm) and processes an average of 1.22 mgd. This plant currently does not produce reclaimed water. The Williams WWTP processes approximately 300,000 gpd (208 gpm) of wastewater; the quantity of reclaimed water produced at this plant, if any, is unknown. Costs and potential environmental impacts that is associated with construction of infrastructure to convey reclaimed water to the project from these plants would be expected to be significant. Therefore, use of reclaimed water from these plants, even if it would be available, is not considered feasible.

Alternative 4: Other Inland Waters

The following inland water supply sources were considered for the project:

- Groundwater from GCID. While primarily a surface water provider, GCID supplements its water supply with groundwater from its own well, located northeast of Willows and adjacent to the Glenn-Colusa Canal, and from more than 160 privately owned wells. In addition, GCID is in the process of installing another well approximately 15 miles north of the existing well that is expected to be operational in 2007. While this source would provide a sufficient and reliable supply to the plant, the use of water from the Tehama-Colusa Canal is preferred due to delivery and avoidance of potentially sensitive habitat (adjacent to the Glenn-Colusa Canal).

- Groundwater at or near the project site. In 2001, three test wells were drilled on site to provide information about the local groundwater regime. The test program, detailed in Appendix O and summarized in Section 8.14.1.1, suggested that a sustained potential yield of about 200 gpm might be available from one onsite location. A sustained safe yield for year-round use was not determined. Because of uncertainty about whether a reliable source of sufficient groundwater is available to meet the proposed project's water supply needs, groundwater was determined to be less reliable than a surface water source.

- Potable water from the Maxwell Public Utility District. The nearest water supply system is in Maxwell, approximately 5 miles southeast of the site. Its annual production capacity is about 3,700 acre-feet. Due to distance and limited capacity of the system, use of this system was determined to be infeasible.

No other inland waters exist; therefore inland water alternatives are considered environmentally and economically infeasible.

9.8 TRANSMISSION INTERCONNECTION ALTERNATIVES

The project site is located approximately 1,800 feet from PG&E's 230 kV transmission system from Cottonwood to Vaca-Dixon. To the west and farther away from the project site is the California-Oregon Transmission Project (COTP) transmission line, which operates at 500 kV. The nearest electrical substation that provides opportunity for interconnection is located at Maxwell and is a distribution substation.

There are only two alternatives for interconnection of the CGS to the transmission grid to provide a path for export of power from the facility: construction of a new transmission interconnection to a nearby electrical substation (substation interconnection), or interconnection directly with the PG&E system (direct connection). More specifically:

- **Substation Interconnection** – To implement this alternative would require construction of a new interconnection transmission line from the CGS switchyard to Maxwell located approximately 5 miles from the project site. This alternative would require acquisition of approximately 5 miles of right-of-way and construction of the interconnection line. This alternative would include disturbance at tower locations, and potential construction of an access road.

- **Direct Connection** – To implement this alternative would involve looping PG&E's existing 230 kV transmission into a new switchyard located adjacent to the CGS. PG&E's existing transmission includes two parallel tower lines, each of which carries two 230 kV circuits. To loop each of these circuits into the CGS switchyard and back to the main transmission line route would involve the construction of four tower lines from the existing PG&E transmission corridor to the CGS. Two tower lines are required to bring the existing four circuits into the switchyard and two tower lines are required to return. These tower lines would be approximately 1,800 feet long, constructed in the area between the CGS site and the existing transmission line. Since this connection would be constructed in the confined area between the power plant and the existing transmission line, limited construction of new access would be required.

The direct connection alternative was selected based primarily on two factors:

- Direct connection requires less transmission line construction, and therefore, less environmental disturbance.

- Substation interconnection provides a lower level of transmission reliability because it is limited by an outage on the single interconnection circuit. Additional reliability could be provided by a second interconnection, but only at increased cost. Direct connection through the CGS switchyard allows interconnection to either or both of the major PG&E transmission circuits, offering an increased level of transmission reliability compared to the substation interconnection alternative.

It should be noted that direct interconnection to the COTP could also be included as an alternative. This interconnection would be configured in a manner similar to the interconnection to the PG&E transmission line. However, since the COTP line is approximately 1.25 miles to the west of the proposed site, the required loop lines for interconnection would be longer. Because this alternative does not offer superior performance/reliability features, it was rejected in favor of the direct connection to the PG&E system.

9.9 GAS SUPPLY ALTERNATIVES

The proposed project will require up to 4,426 million Btu per hour. Delivery of gas in this volume requires interconnection to a major gas transmission line or to a local distribution network with sufficient transmission capacity to serve the power plant's needs.

The CGS site is not located in close proximity to any local distribution system from which gas can be obtained. However, it is located less than one-quarter mile from the existing two PG&E gas transmission lines and Compressor Station.

The other alternative route for delivery of gas to the CGS is construction of a pipeline along the proposed access road. However, PG&E requested that the interconnection be located upstream (i.e., north) of the compressor. No significant environmental impacts from pipeline construction at the proposed location are expected.

The only other gas pipeline alternatives that could be considered would be alternative routes to interconnect to the PG&E system. Because the proposed gas pipeline alternative is the most direct route to the Compressor Station/pipeline, any other alternatives considered would be over a longer route. A longer pipeline route would entail greater construction disturbance and require additional capital investment.

9.10 REFERENCES

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