CHAPTER 3

APPROACH TO ENVIRONMENTAL ANALYSIS

In reading this EIR, it is important to understand the uncertainty involved in predicting the future behavior of PG&E or new plant owners; the legal framework in which this divestiture proposal exists; and the conservative nature of and bases for the assumptions used throughout the document to evaluate the environmental impacts of the project. Although the project itself—transfer of plant ownership from PG&E to new, non-utility owners—is simple and straightforward, this EIR, in its projections, assumptions and methodology, is rather complex. This chapter outlines the approach to the environmental analysis in this EIR and the reasons for the assumptions employed.

3.1 IMPACTS AND MITIGATION MEASURES

Significance criteria have been developed for each environmental issue analyzed in this EIR, and are defined at the beginning of each impact analysis section following the discussion of the environmental setting. Impacts are categorized as follows:

1) Significant and unavoidable;

2) Significant, but can be mitigated to a less-than-significant level; or

3) Less than Significant.

The mitigation measures presented in this EIR that are identified as "Mitigation Measures. Where this EIR determines that no impact will occur as a result of the project, that impact is categorized as less than significant. Proposed as Part of the Project" are proposed by the Project Sponsor (PG&E) and would be implemented if the project is approved. Mitigation measures shown as "Mitigation Measures Identified in This Report" are additional measures identified during the EIR process that could be imposed by the CPUC or other responsible agencies as conditions of approval, or permit requirements, in order to mitigate project impacts. Although mitigation measures are not required under CEQA for less than significant impacts, such measures may be recommended.

3.2 RESTRUCTURING VERSUS DIVESTITURE

In 1996, the CPUC initiated and then suspended preparation of a policy-level Environmental Impact Report (EIR) to study the environmental effects of the entire electric industry restructuring process. The enactment of Assembly Bill (AB) 1890 (Stats. 1996, Ch. 854) took precedence in planning the new electric market. This rendered an EIR on restructuring unnecessary since, with the enactment of AB 1890, the policy of introducing competition into California's electric generation sector in 1998 is now law, and the implementation of laws enacted by the Legislature is exempt from CEQA.

Restructuring itself is likely to lead to profound changes in how the state's electricity system operates. Divestiture, which is the sale of power plants, is intended to further facilitate and cement those changes by altering the incentives that participants, particularly in generation, face. This EIR does not analyze effects associated with the changes brought about by restructuring since such changes have already been mandated and are occurring now. The EIR thus assumes the existence of the restructured market, and analyzes potential impacts associated with projected plant operations under new owners in the restructured market as compared to PG&E's projected plant operations (if the plants were not sold) in the restructured market. At the same time, however, since this EIR does include data on PG&E's historical practices and levels of operation, as well as information about the current environmental setting, observations could be made concerning the effects of both restructuring and divestiture on the existing, or historical, environmental setting.

3.3 ANALYSIS YEARS

BASELINE SCENARIO (1999)

The manner in which PG&E would be expected to operate the plants in 1999 is considered to be the environmental baseline for purposes of measuring the impacts of the project. In most respects, this 1999 PG&E Baseline Scenario does not differ from the existing environmental setting. However, in order to reflect the ongoing changes in the electric industry resulting from restructuring (which changes will occur with or without the divestiture project), it is reasonable and informative to project the manner in which PG&E would operate the plants in 1999 if the plants were not sold. The 1999 baseline assumptions and modeling results are described in Section 3.6.2.

ANALYTICAL MAXIMUM SCENARIO (1999)

In order conservatively to depict the greatest potential project impacts in 1999, the Baseline Scenario is compared to an analytically-derived maximum capacity (the "Analytical Maximum") at which each of the plants proposed to be sold could operate in 1999. The analytical maximum assumptions and modeling results are described in Section 3.6.2.

The year 1999 was selected as the project impact year for three primary reasons:

(1) If the project is approved, the plants could be sold by 1999.

(2) The year 1999 will be the first full year under restructuring of the electric industry in California.

(3) PG&E is currently precluded from selling power outside the Power Exchange and, depending upon the timing of CTC collection, could be precluded from that activity until

> March 31, 2002. New owners, on the other hand, could immediately take advantage of the direct access market, i.e., selling directly to customers. The ability of new owners to immediately participate in the direct access market is a key factor in this EIR's assumption that new owners will tend to operate at higher levels than would PG&E (see Attachment C). Thus, a year prior to 2003—when PG&E will be able to bypass the Power Exchange and sell power directly, thereby moving its operational characteristics closer to those of a new owner—likely represents the greatest potential for environmental change caused by divestiture.

CUMULATIVE SCENARIO (2005)

This EIR analyzes cumulative impacts as of the year 2005. The year 2005 was selected for cumulative analysis primarily because all air quality controls for NOx, as required by Bay Area Air Quality Management District Regulation 9, Rule 11, would be in place by that year. The cumulative impacts analysis is contained in Chapter 5 of this EIR, Cumulative Impacts.

The analysis considers the cumulative effects of a multitude of projects and factors, including proposed new power plants, proposed upgrades in the electricity transmission system, projected increases in demand for electricity, planned or proposed wastewater injection projects at the Geysers plant, and local projects proposed in the vicinities of the power plants. Many of these projects involve separate, project-specific environmental review and require governmental permits and approvals in order to be implemented. The cumulative analysis continues to assume that the owners of the divested plants would operate the plants at their analytical maximum capacities, in order conservatively to depict the greatest potential cumulative impacts in 2005.

In light of the July 9, 1998 agreement between PG&E and the City and County of San Francisco (discussed in detail in Chapter 1, Introduction), the cumulative analysis assumes that the Hunters Point Power Plant located in the City of San Francisco is no longer operating by 2005. In order successfully to model the Analytical Maximum capacities of the plants proposed to be sold, the cumulative analysis assumes that new generation facilities (totaling 480 MW) have been constructed and are operating somewhere north of the Martin Substation (in San Mateo County) in order to replace the Hunters Point plant and to meet anticipated increases in electricity demand. As a variant, the cumulative impacts analysis considers the replacement of the Hunters Point plant with a combination of new generation facilities (totaling 240 MW) and a new transmission line along the San Francisco Peninsula's existing transmission corridor.

The cumulative impacts analysis compares the 2005 Cumulative Scenario to the 1999 Baseline Scenario. The reason that the EIR uses this approach instead of creating a 2005 Baseline Scenario for the analysis is to portray the maximum cumulative potential for environmental change associated with the project. PG&E's projected operations under the 2005 Cumulative Scenario are examined under Alternative 1, the No Project Alternative, in Chapter 6 of this EIR.

In addition to the cumulative analysis for 2005, the air quality analysis (Section 4.5) considers longer-term, cumulative air quality effects in 2015 based on population projections supplied by the Association of Bay Area Governments and extrapolations of air quality projections developed by the BAAQMD.

3.4 FACTORS THAT COULD PRODUCE CHANGE

This EIR considers whether PG&E's proposed divestiture would likely lead to significant effects on the environment as a result of either (1) physical changes associated directly with the ownership transfer, or (2) distinguishable operational changes at the plants proposed for sale, that are different or greater than would occur solely due to restructuring. The factors considered in determining whether divestiture would result in changes that could produce environmental impacts are discussed in the following bulleted items. Changes that are assumed to be reasonably foreseeable—i.e., the project being analyzed in this EIR—versus those that are not expected to occur or would be too speculative to consider at this time are identified in the following section entitled "Assumptions Regarding Changes Resulting From Divestiture."

- *Amounts of Energy Generated at Each Divested Plant and Other Developed and Undeveloped Sites in California and the Western Region.* The plants proposed for divestiture generally have been operated in recent years at less than available capacity. With divestiture, a new buyer of such a power plant could have an economic incentive to operate the facility at higher levels, subject to permit requirements and applicable regulations. Many factors could cause the amount of energy generated at plants throughout California (not just the divested plants) to change. For example, a plant that is the primary income-generating (and energy-generating) asset of a new owner could be run very differently than when it was owned in common with the many other plants within PG&E's Northern and Central California integrated system, even if it were not retired or refurbished in some manner by the new owner. In addition, changes in fuel purchasing arrangements and the immediate availability of the "direct access" retail electricity sales market to new owners could tend to increase generation.

- *Amount and Timing of Construction, Refurbishment, Repowering, or Retirements of Divested Plants, or Other Developed or Undeveloped Sites in California and the Western Region.* A limited amount of new construction of fences, driveways and the like may be necessary to separate the power generating units, which would be divested, from on-site transmission and distribution equipment, ownership of which would be retained by PG&E. In addition, the sale of PG&E's plants to new owners could affect operations, which in turn could affect resource planning decisions at the divested plants and at other plants throughout California and the western grid. The new owners of the divested plants, facing financial conditions different than PG&E (e.g., different assets and liabilities), could then choose to retire or add capital to their new properties. Under California Energy Commission (CEC) rules, power generating capacity could be increased by up to 15 percent per generating unit as part of any refurbishment or repowering, and cumulatively increased by up to 49 MW at a given power plant site, without requiring CEC approval. With that exception, however, expansion or repowering of facilities at the plants would require issuance of new permits and accompanying environmental review. Changes in generation patterns may affect the scale or timing of certain marginal generation facilities elsewhere to be expanded, retired, or built.

- *Maintenance Practices at Each Divested Plant.* If plants were to change owners, the new owners would not have precisely the same operating experience, qualifications, financing, or corporate philosophy as PG&E. New owners may have strong incentives to maintain their facilities to increase availability and resultant sales. A new company could implement measures at a plant that could change maintenance practices (e.g., replace several short duration planned outages with one long one, or reduce total duration of planned outages), or defer maintenance to periods of forced outages. Forced outage durations could be shortened or lengthened, depending on the inventory of spare parts kept on site.

- *Pollution Control Technologies Employed or Installed by New Owners.* Within the restrictions imposed by air districts and permit conditions, new owners could potentially delay or eliminate pollution control measures planned by PG&E. Conversely, they could install additional pollution controls if they wanted to increase generation while continuing to meet air district rules. In addition, differential treatment through the BAAQMD rules (depending on how such rules are retained or amended) could cause new owners of single plants to reduce per kilowatt-hour emissions more rapidly than an owner of several Bay Area plants, or than PG&E.

- *Employment Levels and Related Factors.* As the divested plants are sold, repowered, expanded, retired, or operated in their present forms, employment levels at the plants could be affected. Although AB 1890 requires sold and operating plants to be operated and maintained by PG&E for two years (and PG&E has indicated that it intends to require new owners to recognize its employee unions), no mandate exists that requires the plants to continue to operate after being sold unless they are "must-run" plants (which each of the plants proposed for sale are). Such changes could affect local employment levels, which might have secondary environmental effects.

- *Extent and Character of Land Use.* To the extent that a divested plant site is constrained by surrounding sensitive land uses (e.g., nearby residential areas), new construction at the plant site could increase potential conflicts with existing and potential future land uses. PG&E's proposed contract of sale would require deed restrictions to keep the properties in industrial uses.

- *Approach to Environmental Cleanup.* The change in ownership could affect the cleanup of power plant sites. Selling a power plant to a new entity could change how PG&E approaches any ongoing environmental remediation activities at the site. Such changes could be beneficial. For example, cleanup could be accelerated to provide adequate room for both the new owner to upgrade the generating units and PG&E to retain access and provide upgrades to retained transmission and distribution facilities, or simply as part of the purchase and sale transaction. Issues associated with the liability for environmental cleanup are expected to be resolved contractually between each new owner and PG&E.

- *Permit Transfers for Divested Plants.* Some regulatory requirements for the PG&E plants would cease to apply to plants sold to non-CPUC-regulated parties. The Bay Area Air Quality Management District has stated its intention to modify its Regulation 9, Rule 11, which currently applies to CPUC-regulated utility power plants. No barriers to such changes are apparent. However, the permit changes may cause the new owners to make different decisions than PG&E would if the plants continued under PG&E's ownership.

3.5 ASSUMPTIONS REGARDING CHANGES RESULTING FROM DIVESTITURE

Having considered the factors in Section 3.4, above, the environmental analysis in this EIR is based on assumptions of reasonably foreseeable changes that could result from divestiture, in terms of power plant operating characteristics, new construction, repowering or retirement of units, and employment levels. This section describes, based upon economic and operational analyses of PG&E's proposed divestiture, the projected changes likely to result from divestiture compared to the changes expected to stem from restructuring alone, without divestiture. The economic and operational analyses (discussed in further detail in Attachment C and Attachment G) form the basis for the environmental analysis in this EIR.

Implementation of the project would not affect the type of fuel used to fire the four power plants. The new owners of the Potrero, Pittsburg, and Contra Costa plants would continue to use natural gas as the primary fuel, and low sulfur, residual fuel oil only as back-up, for the boilers that provide steam for the steam turbines at those plants. In comparison to fuel oil, natural gas is relatively inexpensive, reduces maintenance costs and is cleaner burning. The combustion turbines at the Potrero plant would continue to use distillate fuel and would primarily be used only when electricity demand is very high or when demand is moderately high and key generating units within San Francisco are out for maintenance. The Geysers plant would continue to be powered only by steam from the geothermal steam field.

The manner in which operations at the Geysers geothermal plant could change with divestiture depends on the identity of the new owners. In light of the declining steam fields and various economic factors, PG&E has recently moved many Geysers units from baseload (i.e., constant) operations to more cyclical operations that follow the demand load. If a third-party entity with no ownership interest in the underlying steam fields purchases the Geysers units, it is reasonably foreseeable that such new owner would continue to pay a steam price similar to that paid by PG&E under its contracts with the steam field owners. Given this assumption, it can be reasonably foreseen that the plants would be operated in a manner similar to PG&E's operation of the Geysers plant in a restructured setting, perhaps with less cycling because of higher per kilowatt-hour transaction costs for new owners selling into the PX or the ISO. To the degree that the new owners can sell directly to the "green power" market, production at the Geysers may increase over the levels at which PG&E would have operated. If, on the other hand, the current steam field owners and suppliers, UNT and Calpine, purchase the respective Geysers units, it is foreseeable that the plant would be operated more either in a baseload manner or during peak periods to increase dependable capacity, thereby increasing generation from the Geysers plant. The basis of such expectation is that if the steam field owners also owned the generation units, these owners would be able to sell power directly into the "green power" market, and would have lower effective steam prices than would either PG&E or a third-party new owner.

As to the three fossil-fueled facilities, it can be reasonably foreseen that non-utility generators will operate these plants differently than PG&E would operate those facilities without divestiture in a restructured world. If it did not divest the three plants, PG&E would be expected to continue to submit bid packages to the Power Exchange (PX) to run the more efficient units at high capacity levels and use the less efficient units only when their capacity is needed, similar to the manner that PG&E operated the plants prior to restructuring. In contrast, new owners would have incentives to operate their newly acquired plants in a more constant mode, particularly if the new owners do not own any other plants in the region. Furthermore, new owners could immediately sell power directly to users (through direct access) in addition to selling to the PX. By contrast, PG&E is constrained to selling only to the PX prior to market valuation of the plants.

Attachment C was prepared primarily to answer the question of whether new plant owners would tend to generate more electricity than would PG&E in a restructured setting. The analysis in Attachment C discusses three factors that may cause a tendency of new owners of the fossil-fueled plants to operate at higher levels, particularly during the transition period prior to 2002: (1) the portfolio effect, which is the availability to PG&E of its portfolio of electricity-generating assets, (2) fuel procurement practices, such as the possibility that new owners would purchase natural gas at a lower cost per unit or in a different fashion than would PG&E, and (3) the ability of new owners immediately to participate in the direct access market while PG&E must initially sell all of its power through the PX.

It is noteworthy that the plants could eventually be sold without approval of the CPUC, so the physical and operational differences between restructuring with divestiture as currently proposed and without divestiture could, as a practical matter, be minimized or even eliminated, except in the period before market valuation of the plants. With restructuring and without divestiture of the four plants, the market value of the plants must by some means be established and approved by the CPUC no later than the end of 2001. Once market valuation occurs, the plants could be sold without CPUC approval. Thus, implementation of restructuring itself could result in plants being sold after their market value is established. PG&E would not be required to sell its plants, and it is not certain that the plants would be sold.

Since PG&E will be able to participate in the direct access market as of 2002 (or sooner if their plants' market values are approved by the CPUC), the tendency of new owners of the fossil-fueled plants to generate more than PG&E lessens after the transition period. Thus, the environmental effects of divestiture that may be associated with increased generation, to the extent that such generation flows from the ability to participate in the direct access market, would be temporary.

At the time of preparation of this EIR, the identities of the purchasers of the plants are not known. However, the general characteristics of the buyers of the plants previously divested by PG&E and Southern California Edison are known. The greatest potential for increased generation at a fossil-fueled plant would exist if the plant were bought by a separate, independent entity that owns few or no other generation facilities within California. If a single entity buys several plants and/or owns other generating facilities (e.g., wind power, coal, and/or hydroelectric plants), or to the extent that singly-owned plants are reconstituted into larger portfolios in the future, the tendency of such a new owner to operate the divested plants more than the PG&E would decline, though not remarkably so compared to the large portfolio owned by PG&E.

According to CEC forecasts, electricity demands are expected to increase throughout California in the future. In certain areas (e.g., San Diego and San Francisco), additional electrical capacity will be needed to meet these future demands. It is not anticipated that this divestiture project will affect the future demand for electricity in California to any considerable degree. Therefore, for the most part, any increase in generation at a divested plant would be offset by a decrease in generation elsewhere. While some increased generation within California could be offset by a decrease in electricity imports from out of state, it is also possible that increased generation at a divested plant would be offset by a decrease in generation at other plants in California.

This EIR assumes that each of the divested plants would operate within the parameters of its existing permits (e.g., water discharge permits and air emissions permits) because it is not reasonably foreseeable that operations would exceed those levels. Operations in excess of permitted levels or repowering would require new discretionary permits and environmental review.

Construction activities that are expected as a result of divestiture would be minor (i.e., construction of fences to separate properties being sold or retained). Non-physical changes would include subdivision of the properties as necessary to complete the sales.

Increases in operations stemming from divestiture could result in a minimal increase in employment at the plants.

The precise manner in which PG&E would operate the plants in the future restructured environment is difficult to predict. PG&E could operate the plants up to their existing permitted levels (i.e., to the level allowed by the most constraining permit) without any additional approvals or environmental review. Under restructuring, PG&E may operate its retained facilities at higher levels than historical levels of operation, and could operate those facilities up to their permit limits. This means that increased generation at the plants proposed for divestiture could occur without divestiture. There are simply grounds for believing that it is more likely to occur with divestiture.

As the foregoing discussion indicates, the degree to which generation would increase at the plants slated for divestiture is highly uncertain. As shown in the analyses of Attachment C, the only conclusion that can be drawn concerning future operation of the fossil-fueled plants targeted for divestiture is that overall, incentives exist that create a tendency for the new owner to operate a divested plant at higher levels than PG&E would operate that plant in the future. A new owner of the Geysers plant, however, would be expected to operate at a level similar to that of PG&E, unless the new owner were also a steam supplier, in which case the new owner would have a tendency to operate at higher levels than PG&E would operate the Geysers plant in the future.

3.6 MODELING ASSUMPTIONS AND RESULTS

The primary impact analyses in this EIR consider the difference between PG&E's projected operations of the plants and the projected analytical maximum operations of the plants (explained in Section 3.6.2, below). The level of operations at each plant is indicated by the plant's annual "capacity factor," i.e., the percentage of operations compared to the rated capacities of the collective units of the plant. The annual capacity factor of an individual unit (or, collectively, a plant) is a function of both the amount of time that the unit is operating and the level at which the unit is operating. For instance, if a hypothetical unit were on and operating 100 percent of the time at 50 percent of its rated capacity, it would have a 50 percent capacity factor. Similarly, if a hypothetical unit were on and operating 50 percent of the time, but at 100 percent of its rated capacity, it would also have a 50 percent capacity factor. Combining these concepts, if a hypothetical unit were on and operating 50 percent of the hours of the year and at a 50 percent level for each of the hours it was on, it would have an annual capacity factor of 25 percent.

The capacity factors used in the EIR and discussed below were derived using the SERASYM™ unit-specific, California-wide data set, which was processed by the SERASYM™ production cost model to forecast plant operations. The computer modeling was conducted by Sierra Energy and Risk Assessment, Inc. (SERA), a California company that developed the model and has been running it for more than a decade. In developing modeling assumptions, SERA used the best and most reliable data available to the CPUC during the preparation of the Draft EIR, although no model can precisely predict operations under, and conditions in, the restructured market. The key modeling assumptions used in deriving the capacity factors for the 1999 Baseline Scenario, the 1999 Analytical Maximum Scenario and the 2005 Cumulative Analytical Maximum Scenario are described below. No modeling was necessary for the 2015 air quality analysis. An expanded list of modeling assumptions, and discussion of the modeling, is presented in Attachment G to this EIR.

3.6.1 1999 BASELINE SCENARIO

Table 3.1 presents capacity factor estimates (the percentage of total plant capacity) for operation of the four plants in a restructured setting in 1999 if they were not sold, but were retained by PG&E ("1999 Baseline"). The major assumptions used in this baseline computer simulation include:

1. PG&E continues to own and operate the Potrero, Pittsburg, Contra Costa and Geysers plants, obtaining revenue through reliability contracts with the Independent System Operator (ISO) and by selling power from the facilities through the Power Exchange (PX).

2. Both the PX and ISO continue to commit and dispatch the plants based on minimum variable cost of operation, consistent with the requirements of the San Francisco Operating Criteria (SFOC) and the Bay Area Reliability Requirements (BARR) and local distribution system voltage support requirements.

3. PG&E installs planned emission control equipment and continues to operate the three fossil-fueled plants proposed for sale and the Hunters Point Power Plant to keep total combined NOx emissions from its four Bay Area steam boiler plants below the NOx concentrations specified by the Bay Area Air Quality Management District in Regulation 9 Rule 11.

4. The Contra Costa and Pittsburg Power Plants are operated in full compliance with existing Delta Water Quality Maintenance Requirements including special, non-economic operation of Pittsburg Unit 7 during the period May through mid-July.

5. The hourly demand loads for San Francisco in 1999 employ the 1997 actual load shape, plus assumed continuation of the average annual rate of load growth observed between 1991 and 1997.

6. Geothermal steam availability at the Geysers continues its observed slow rate of decline, as modified to reflect implementation of the Lake County wastewater injection project.

7. PG&E's Geysers units are economically dispatched, per the steam prices and operational flexibility in existing steam supply contracts.

TABLE 3.1
PROJECTED POWER PLANT ANNUAL CAPACITY FACTORS[a]

Plant	Unit	Type	Fuel	Net Capacity (MW)[b]	1999 Baseline (No Project)	Plants with Lowest Natural Gas Price (1999): All Plants	Contra Costa and Pittsburg	Potrero	1999 Analytical Maximum[c]	2005 Cumulative Analytical Maximum[d]
Potrero	3	ST	NG	207	41	68	41	76	76	64
	4	CT	DF	52	3	3	3	3	3	9
	5	CT	DF	52	2	2	2	2	2	8
	6	CT	DF	52	1	1	1	1	1	7
	Annual Plant Capacity			363 [e]	25	39	24	44	44	40
New 480 MW S.F. Plant		CC	NG	480	NA	NA	NA	NA	NA	91
Contra Costa	6	ST	NG	340	32	71	71	32	71	70
	7	ST	NG	340	40	88	88	40	88	69
	Annual Plant Capacity			680 [e]	36	80	79	36	80	70
Pittsburg	1	ST	NG	163	23	43	43	23	43	45
	2	ST	NG	163	23	68	69	23	69	70
	3	ST	NG	163	33	76	76	33	76	retired
	4	ST	NG	163	28	66	66	28	66	retired
	5	ST	NG	325	39	81	80	39	81	60
	6	ST	NG	325	40	88	87	40	88	76
	7	ST	NG	682	27	57	58	27	58	71
	Annual Plant Capacity			1984 [e]	31	68	68	31	68	56/67 [f]
Geysers	5	G	GS	39/39	68	58	59	68	58	82
	6	G	GS	39/39	68	58	58	67	58	81
	7	G	GS	38/37	72	65	65	71	65	85
	8	G	GS	38/37	72	64	65	71	64	86
	9	G	GS	32/32	54	47	49	54	47	73
	10	G	GS	32/32	54	47	49	54	47	73
	11	G	GS	56/56	46	36	38	45	36	94
	12	G	GS	39/39	76	65	68	77	65	85
	13	G	GS	73/69	95	94	94	94	94	95
	14	G	GS	61/61	81	70	73	81	70	87
	16	G	GS	73/69	94	94	94	94	94	94
	17	G	GS	47/47	78	70	71	77	70	89
	18	G	GS	58/62	82	73	75	83	73	88
	20	G	GS	44/46	78	67	70	78	67	86
	Annual Plant Capacity			669/665 [e]	75	68	69	75	68	87

TABLE 3.1 (Continued)
PROJECTED POWER PLANT ANNUAL CAPACITY FACTORS[a]

NOTE: The capacity factors were derived using the SERASYM™ unit-specific, California-wide data set, which was processed by the SERASYM™ production cost model to forecast plant operations.

UNIT TYPES:			FUELS:			
	CT	combustion turbine		NG	natural gas with residual oil backup	NA = not applicable
	ST	steam turbine		DF	distillate fuel oil	
	G	geothermal steam		GS	geothermal steam	
	CC	combined cycle				

a Capacity factor is the ratio (expressed as a percentage) of operations of a unit or plant to the rated capacity of the unit or plant.

b Although the net capacity of Unit 7 at the Pittsburg Power Plant is listed as 720 MW in PG&E's PEA, other sources (including the Master Must-Run Agreement between PG&E and the ISO and the Bay Area Reliability Dispatch Requirements) identify the unit's maximum net capacity as 682 MW. Based on this information, the SERASYM™ model results used in this EIR reflect the 682 MW factor.

The net capacity of the Geysers Power Plant is actually 1,224 MW (see Table 2.1 in Section 2, Project Description). The net capacities shown here are the predicted capacities for the plant based on projected steam availability in 1999 and 2005, respectively.

c For the fossil-fueled plants, the 1999 analytical maximum capacity factor for each unit is the highest of three model runs shown immediately to the left in which (1) all three plants receive equally low gas prices, (2) the Contra Costa and Pittsburg plants receive the lowest gas price, and (3) the Potrero plant receives the lowest gas price. For the Geysers plant, the 1999 analytical maximum capacity factor is the lowest of the three model runs, since such lower operations may result in environmental impacts from steam stacking.

d This scenario reflects the replacement of PG&E's Hunters Point Power Plant in San Francisco with a new 480 MW power plant in combination with divestiture and other cumulative projects. The 2005 cumulative analytical maximum was modeled using only the "All Plants" case because model sensitivity runs showed these results to be very similar to the runs that had the lowest natural gas price going to just the Contra Costa and Pittsburg plants or the Potrero plant.

e Net capacity for the entire plant.

f The total net generating capacity of the Pittsburg Power Plant would decrease in the future due to the retirement of certain generating units. In order to meaningfully portray changes in generation, two annual plant capacity numbers are presented. The first number reflects the annual plant capacity factor based upon the current total net generating capacity of the plant (where all seven units are operational), which is 1,984 MW. The second number reflects the annual plant capacity based upon the combined net generating capacity of the units that are assumed to operate in 2005.

SOURCE: Sierra Energy and Risk Assessment, Inc., and ESA, 1998.

8. The CEC's recently adopted forecast of natural gas prices for all regions of California are employed for all gas-fired plants, and the CEC's companion inflation forecast series is used to adjust other generation costs, including maintenance.

3.6.2 1999 ANALYTICAL MAXIMUM SCENARIO

As discussed above in Section 3.5, it is expected that divestiture of the power plants will create a tendency for new owners to operate the plants at higher levels than in the 1999 Baseline Scenario. However, it is not possible to determine with any precision at which plants operations would increase, or the degree to which operations would increase at any particular plant. The 1999 Analytical Maximum Scenario calculated by the computer model is intended to capture the maximum possible change in operations that could occur from divestiture. Table 3.1 presents capacity factor estimates for operation of the four plants in 1999 at their Analytical Maximum capacities.

The Analytical Maximum capacity factors for the four plants represent the highest capacities at which the plants could operate, taking into account limiting factors such as the rated capacities of the units; scheduled and forced outages of units for maintenance; contractual limitations, including must-take contracts that favor power generated by qualifying facilities (QFs); and demand constraints (i.e., the finite demand for electricity at any particular time on any given day). The 1999 Analytical Maximum Scenario reflects assumptions 2 through 8 outlined above for the 1999 Baseline Scenario and, additionally, assumes for the fossil-fueled plants that natural gas could be purchased in unlimited quantities at a 25 percent discount from the least expensive supply of gas assumed to be available to fuel California power plants (i.e., the natural gas supplied for the Cool Water plant). The purpose of this assumption was to remove, to a great degree, the cost of fossil fuel from the new owner's decision whether and when to generate power. Although it is extremely unlikely that such a reduced gas price could be obtained, this assumption further strengthens the conservative nature of the impacts analysis. To achieve the 1999 Analytical Maximum Scenario, the model was run once for the Potrero plant alone and again for the Pittsburg and Contra Costa plants together (since they are proposed to be sold as a bundle), so that during each of these two model runs only the Potrero plant or the Pittsburg and Contra Costa plants received the least expensive gas price. The model was also run with all three plants receiving the lowest gas price. The highest capacity factor was selected for each unit of the three runs to derive the 1999 Analytical Maximum Scenario. The 1999 Analytical Maximum Scenario for the Geysers plant assumes the minimum level of modeled operations for the Geysers units since such lower operations may result in environmental impacts from steam stacking and resulting unabated steam releases. Historically, the main cause of steam field stacking has been the failure of the 230 kV transmission lines at the Geysers plant. However, any cause for shutdown of the units has the same result. Lake County has expressed a concern that excess hydroelectric power during the spring (causing the Geysers plant to be uneconomical) could be a factor that limits the new owner's output.

In order to be conservative, the EIR's project impact analyses assume that the new owners would operate the divested plants at the 1999 Analytical Maximum capacities. However, for the reasons discussed above, operations are not expected to reach these levels at each plant, and operations may not reach such levels at any particular plant. It is merely the possibility that operations could increase within this range of capacity factors that is evaluated in this EIR.

3.6.3 2005 CUMULATIVE ANALYTICAL MAXIMUM SCENARIO

The capacity factor estimates for the 2005 Cumulative Analytical Maximum Scenario are presented in the last column of Table 3.1. These modeled estimates were derived in the same manner as those of the 1999 Analytical Maximum Scenario, with the following additional key assumptions:

1. The Hunters Point Power Plant is retired, and replaced with a new plant consisting of two 240 MW units (for a total of 480 MW) to satisfy existing electricity needs, plus the projected cumulative increase in demand for electricity within the City and County of San Francisco.

2. New plant owners complete all planned air emission control improvements as listed in Table B-2 of PG&E's Proponent's Environmental Assessment for the three fossil-fueled plants, including the retirement of Pittsburg Power Plant Units 3 and 4. Although listed by PG&E as being retired by 2005, Pittsburg Units 1 and 2 are retained for voltage support, with a selective catalytic reduction (SCR) system installed on Pittsburg Unit 2 in order to comply with Bay Area air quality limits in 2005.

3. New generation is added in San Diego before 2005 to alleviate the predicted capacity shortage in that region.

4. New generation currently under construction in Nevada is added and the High Grove and San Bernardino power plants in Southern California are repowered consistent with CEC siting requirements and South Coast Air Quality Management District permit procedures.

5. The owner of the El Segundo Generating Station in southern California produces 70 MW of generation at all times to replace the base-load in the existing El Segundo refinery adjacent to the power station.

6. Projected transmission upgrades, described in detail in Chapter 5, Cumulative Impacts, are in place.

7. The two proposed wastewater injection projects described in detail in Chapter 5, Cumulative Impacts, are being implemented, and have helped to stabilize generation capacity at the Geysers plant.

Modeled estimates were also developed for two cumulative variants. One of these assumes that the Hunters Point Power Plant is replaced by upgraded transmission facilities on the San Francisco Peninsula, together with construction of a new 240 MW generating facility to serve electricity needs within San Francisco. The other variant assumes that the proposed Pittsburg District Energy Facility is constructed in the City of Pittsburg. The details of, and modeling results for, those variants are set forth in Chapter 5, Cumulative Impacts, of this EIR.