CHAPTER 2
WRITTEN COMMENTS AND RESPONSES

This chapter reproduces the comment letters received regarding the August 5, 1998 Draft Environmental Impact Report (DEIR). Each comment letter is succeeded by responses. The responses emphasize issues related to the adequacy of the EIR in identifying and analyzing the possible environmental impacts of the project and possible approaches for avoiding or mitigating these impacts.

Some comments include issues that are not related to the adequacy or contents of the DEIR. Detailed responses have not been prepared for these comments, but they are acknowledged in this document. Because all of the comments received regarding the DEIR are reproduced herein, they are part of the Final EIR for this project. As such, these comments will be considered by project decision-makers as they decide whether to approve the proposed project or one of the alternatives evaluated in this report.

Comment letters from agencies are included first, followed by letters from individuals. Each agency or individual has been assigned a letter (e.g., “A”), and each comment has been assigned a number. Therefore, a unique descriptor, consisting of a double letter and number, applies to each comment and response. For example, “response A1” refers to the response to the first comment from agency A. These descriptors appear on each letter to indicate what text is considered part of each comment.

In responding to some of the comment letters, it was necessary to make revisions to the text of the DEIR. In these instances, the page number where the text is revised has been provided. Additions to the DEIR text are shown in underline, while deletions to the text are noted by strike-through lines.

A glossary of terms and a list of acronyms used in this document are provided in Chapter 6.

September 21, 1998

Bruce Kaneshiro
California Public Utilities Commission
225 Bush Street, Ste. 1700
San Francisco, CA 94104-4207

Subject: PG&E Application to Sell Generating Plants (#98-01-008)
SCH #: 98082013

Dear Bruce Kaneshiro:

[Begin A1]
The State Clearinghouse submitted the above named environmental document to selected state agencies for review. The review period is closed and none of the state agencies have comments. This letter acknowledges that you have complied with the State Clearinghouse review requirements for draft environmental documents, pursuant to the California Environmental Quality Act.
[End A1]

Please call Kristen Derscheid at (916) 445-0613 if you have any questions regarding the environmental review process. When contacting the Clearinghouse in this matter, please use the eight-digit State Clearinghouse number so that we may respond promptly.

Sincerely,

Antero A. Rivasplata
Chief, State Clearinghouse

Note: Included with this comment was one page of the Notice of Completion Document Transmittal Form. Since these cannot be reasonably duplicated here on this web page they are not available electronically. Should the viewer require a copy of these, please contact Webmaster for a printed copy.

STATE AGENCIES

A. STATE CLEARINGHOUSE

A1 Comment noted. The Governor's Office of Planning and Research acknowledges that the California Public Utilities Commission has complied with the State Clearinghouse review requirements for draft environmental documents, pursuant to CEQA (SCH# 98082013).

September 12, 1998

Mr. Bruce Kaneshiro
Project Manager
Environmental Science Associates
225 Bush Street, Ste. 1700
San Francisco, CA 94104

RE: **California Energy Commission Comments of the CPUC's Draft Environmental Impact Report for Application 98-01-008, Pacific Gas and Electric Company's Application for Authorization to Sell Certain Generating Plants and Related Assets**

Dear Mr. Kaneshiro:

Thank you for the opportunity to review and offer comments on the Draft Environmental Impact Report for Application 98-01-008, Pacific Gas and Electric Company's Application for Authorization to Sell Certain Generating Plants and Related Assets.

The Energy Commission Staff recognizes the tremendous effort that has gone in to the development of this analysis and report. In support of these efforts, the Commission offers the attached comments. If you have any questions regarding these comments, do not hesitate to contact me.

Sincerely,

Robert L. Therkelsen
Deputy Director for Energy Facility Siting and
Environmental Protection Division

Attachment

California Energy Commission Comments on the CPUC's Draft Environmental Impact Report for Application 98-01-008, Pacific Gas and Electric Company's Application for Authorization to Sell Certain Generating Plants and Related Assets

September 21, 1998

General Comments

[Begin B1]
1. The Energy Commission Staff agrees that determining the actual plant operations under new ownership is not possible, and, therefore, a conservative analysis is appropriate to determine the potential for adverse environmental impacts. We concur with the decision to establish a baseline and an "analytical maximum" as a basis for this impact analysis. The Energy Commission Staff agrees that it is reasonable to assume the new owners will increase operation of these power plants above the baseline for the characterization of the analytical maximum.
[End B1]

[Begin B2]
2. Energy Commission policy is that restructuring should create no increase in adverse environmental effects; we concur that no net increase in adverse environmental impact should occur as a result of this "project".
[End B2]

[Begin B3]
3. The Energy Commission Staff supports modifying Regulation 9, Rule 11 of the Bay Area Air Quality Management District's (BAAQMD) rules for NOx emission to reflect changes in power plant ownership and ensure that emission limits would apply to new owners.
[End B3]

[Begin B4]
4. The Energy Commission Staff is pleased to see that "green" alternatives have been included, but believes a more realistic alternative should be used (e.g., a mix of "green" options and perhaps some distributed generation).
[End B4]

[Begin B5]
5. The text does not define "decommissioning in a responsible manner" (see Section 2.2.2) and therefore does not provide clarity on how the adverse environmental impacts will be avoided during decommissioning. Nor does the text discuss any decommissioning requirements contained in leases or contracts that affect plants to be sold to private owners. The Energy Commission Staff recommends that a more thorough discussion on decommissioning requirements or criteria be included in the report to support the conclusion that no significant adverse environmental affects will occur during this period. This discussion should include a description of applicable federal, state and local laws, ordinances, regulations and standards as well as any lease or contract requirements.
[End B5]

[Begin B6]
6. The cumulative impacts analysis in both Sections 4 and 5 needs to be modified and updated to reflect changes in the market and more accurately evaluate potential impacts. For example, with a setting of 2005 for the environmental analysis, the Pittsburg and Contra Costa power plants should include increased operation of both facilities and the addition of Enron's proposed power project in the Pittsburg area. Calpine's Pittsburg project and any other projects should be included as if they are filed prior to certification of this EIR. Air dispersion impacts modeling should include the Contra Costa, Pittsburg, and Enron Pittsburg power projects, and the potential industrial development in the Pittsburg area to best reflect the impacts of the divestiture project.
[End B6]

Specific Comments

[Begin B7]
Page 2.5, line 3: What does "quantities of contaminants" mean? This needs to be stated differently, or additional informational provided for the reader to understand what is intended.
[End B7]

[Begin B8]
Page 2-6: "...PG&E's Application...also seeks authority to transfer all rights and obligations under its steam contracts...". We recommend that the "obligations" pertinent to decommissioning be spelled out as a new heading under Project Description.
[End B8]

[Begin B9]
Page 2-6, First paragraph, second sentence, Geyser's Power Plants: Add footnote indicator to the end of the sentence, for the following footnote:

> "The California Energy Commission certified Units 16, 17, 18, and 20 for construction and operation. The Energy Commission must approve any change in ownership of these power plants. Any new owner will be expected to comply with all existing conditions of certification, including decommissioning."

[End B9]

[Begin B10]
Section 3.6, Modeling Assumptions and Results: The conclusion that Pittsburg units 3 & 4 will be retired by 2005 is not well supported or explained in the text. Are there specific legal or contractual requirements for the retirement of Pittsburg units 3&4 by 2005? As acknowledged on page 3-4, there are factors that may change the operation characteristics of the divested facilities that may, in turn, affect the closure date. The assertion is made on page 3-6 that "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." Consistent with the methodology to estimate the analytical maximum to determine the potential for environmental impacts, we recommend that continued operation of Pittsburg units 3&4 (total capacity 326 MW) beyond 2005 and subsequent adverse environmental impacts be accounted for in the analysis. The base case should include the retirement of these units. However, if there are

conditions which ensure the retirement of these units such conditions or requirements should be thoroughly discussed in the analysis.
[End B10]

[Begin B11]
Page 4.5-68: Table 4.5-32 shows that the Pittsburg power plant causes a violation of the State 1-hr NO2 standard for the 1999 Baseline and 1999 Analytical Maximum cases when project specific impacts are added to the Delta Region Background.

The EIR provides several plausible explanations for the violation, including the conservatism inherent in the modeling, and concludes that the violations will probably not occur. We believe that by showing the violations in the table, many readers will assume, albeit incorrectly, that the Pittsburg plant is causing unhealthy ambient air quality conditions. The preparers of the Draft EIR should perform refined modeling and provide additional discussion to more clearly show the actual impacts of the Pittsburg facility. This will provide a more representative baseline to which the divestiture project can be compared. In addition, we have the following concerns regarding the findings about the Pittsburg plant:

1) The analysis in the DEIR appears to be double counting the effect of the Pittsburg plant by adding the project specific impacts to the background that should already include the ambient air quality effect of the Pittsburg plant. In addition, the DEIR lacks an adequate discussion of why the Delta Region Background is representative of ambient conditions.

2) In performing the ozone limiting method for the Pittsburg modeling, we strongly suggest that you use an hour-by-hour calculation of the ozone and NO2 levels to most accurately reflect the effects of ozone on NO2 impacts. This would also resolve the uncertainty expressed at the bottom of page 4.5-67 whether the ambient ozone and NO2 maximums would occur simultaneously.

3) The project specific air dispersion impact modeling for both the Contra Costa and Pittsburg cases should consider the overlapping impacts likely from Contra Costa and Pittsburg power plants, and incorporate the dispatch order of Pittsburg and Contra Costa necessary to achieve the Delta Water Quality Maintenance Requirements.
[End B11]

[Begin B12]
4) The project specific impact modeling for the Potrero case should consider any overlapping impacts likely from the limited operation of the Hunters Point project.
[End B12]

[Begin B13]
Page 4-8.1, 2nd paragraph: The percentages for electricity consumption by sector appear to be in error. According to the Energy Commission's 1998 Baseline Energy Outlook, the electricity consumption by sector is: industry 22%; commercial 35% and residential 30%; agriculture 7%, and other 6%. If these numbers are not in error, we recommend more explanation as to what is being represented.
[End B13]

[Begin B14]
Section 4.8 Energy and Mineral Resources, Pages 4.8-4 and 4.8-5: The Energy Commission Staff agrees that it is likely to be in the interest of the new owners of the power plants to operate the facilities as efficiently and as often as possible. However, based on the DEIR conclusion that the units will increase operation, it is unclear if the increased operation of the fossil fired power plants being sold is an efficient use of non-renewable resources if such operation displaces more fuel efficient, cleaner generation unit elsewhere in the state. Please provide more explanation or justification for the conclusion offered in this section.
[End B14]

[Begin B15]
Section 5.2.2, "Future Power Plant Development": Since the cumulative impacts analysis is based on a 2005 maximum, the Commission suggests that this discussion be updated to reflect the following:

Page 5-5 and 5-6: Add additional "expected applications" to discussions:

1) Long Beach District Energy Facilities, which is a nominal 500 MW cogeneration facility, natural gas fired combustion turbine generators, to be located on the port of Long Beach. The Energy Commission expects the application for certification to be filed in October/November 1998.

2) Sunrise Generation and Power Company's proposed cogeneration facility with a nominal 340MW capacity and consisting of two gas turbines and two heat recovery steam generators. The project is to be located in an active oil field approximately 3 miles northeast of Fellows in western Kern County, California. The Energy Commission expects the application to be filed in November 1998.

3) Calpine Corporation and Bechtel Enterprise's joint venture to develop a 535 to 800 MW generating facility at the Dow Chemical site in Pittsburg California. The Commission expects the application to be filed in November 1998.

Page 5-6: Strike the last sentence in the final bullet regarding La Paloma and insert: An AFC for La Paloma was filed on August 12, 1998 and the application was deemed complete on August 26, 1998.
[End B15]

[Begin B16]
Section 5.3, Potential Cumulative Effects: By separating out the consideration of impacts associated with future project developments (Section 5.2) from the impacts associated with either new power plant developments or transmission line developments and the increased capacity factors for the power projects being sold, the cumulative impacts analysis is misleading and inconsistent with the conservative analytical maximum approach. To ensure a more accurate analysis of potential cumulative impacts and consistency with the intent of the analytical maximum, the Energy Commission Staff recommends that analysis for Variant I and II (Sections 5.3.3 and 5.3.4) incorporate the following:

1) the proposed Calpine/Bechtel power plant project to be located in Pittsburg. Since the setting is 2005, this project needs to be a part of the cumulative impacts analysis in

addition to the Enron Pittsburg project because the proponents expect the plant to be operational before 2005.

2) impacts associated with the future projects discussed in Section 5.2.

3) the potential adverse environmental impacts of simultaneous operation of the four power plants in the Pittsburg/Contra Costa area in combination with the reasonable foreseeable projects described in section 5.2.5 for Pittsburg and Contra Costa in order to identify "the maximum possible change effected by the project" (see page 5-16).

[End B16]

[Begin B17]
Page 5-17, Table 5.2 PDEF has a nominal rating of 500MW, not 450MW.
[End B17]

[Begin B18]
Page 5-42 To the extent appropriate, update data and references to the 1998 Baseline Energy Outlook, Final Staff Report August 1998 (P300-98-012).
[End B18]

B. CALIFORNIA ENERGY COMMISSION

B1 Comment noted.

B2 Comment noted.

B3 Comment noted.

B4 The examination of green power in the Alternatives section (page 6-3) of the DEIR was done at the request of the City and County of San Francisco and members of the community near the Hunters Point and Potrero Power Plants, which had expressed a desire to close the power plants and replace that generation with green power resources. Such a proposal was not formally considered as a "project alternative," as defined by California Environmental Quality Act (CEQA), but was informally analyzed as part of the alternatives analysis, with an explanation of why such an alternative was not feasible. The California Energy Commission (CEC) is correct in that use of a mix of green power resources and distributed generating resources could conceivably allow the closure of Hunters Point and Potrero Power Plants (i.e., could meet load demand and the requirements of the San Francisco and Greater Bay Area Operating Criteria). However, such a scenario in the near-future is highly unlikely. Because of its relatively high cost, distributed generation technology (which is basically the use of many small generating units, such as utility-scale fuel cells, distributed throughout a service territory) is still nascent, especially non-polluting distributed generation technology, and is currently not used anywhere in North America. Such a mixture of resources may be considered as an option in the process for planning the closure of the Hunters Point Power Plant, whether by the City and County of San Francisco or PG&E. However, neither the complete nor the partial replacement of existing generation facilities with green power and distributed generating resources represents a true CEQA alternative to the proposed sale of the Pittsburg, Contra Costa, and Potrero Power Plants and the Geysers geothermal units. Thus, examining a "more realistic" alternative of using green power and distributed generation resources in the EIR would not change the EIR's conclusions or add meaningful data to the current decision-making process.

B5 The issue of concern in this EIR is whether a greater environmental risk would exist under the new owner of the divested power plants compared to continued ownership by PG&E, whether referring to future decommissioning of the plants or any other facet of power plant ownership. Many factors affect the assessment of this risk. Concerning decommissioning, the new owner would be required to abide by all contractual requirements, including decommissioning requirements, that currently apply to PG&E because all leases, contracts, agreements, conditions, covenants, and requirements affecting the plants would be assigned to the new owners. In addition, all applicable federal, state and local laws, ordinances and regulations concerning decommissioning would continue to apply to new plant owners.

Regarding the fossil-fueled plants, PG&E is subject to the same decommissioning requirements as apply to any owner of similar facilities, such as the hundreds of power plants in California owned by non-utility companies. PG&E's status as a regulated utility does not reduce or enlarge the scope of applicable requirements. In general, owners of fossil-fueled plants have discretion over the timing and method of decommissioning and dismantling a facility. However, a number of state and federal laws, local ordinances, and permit and lease conditions require demolition activities, site remediation, and handling and disposal of hazardous materials at industrial sites to be conducted in an environmentally responsible manner. Some requirements take effect upon cessation of operations, whereas others take effect when the decision is made to dismantle all or part of a facility.[1]

Regarding the Geysers Geothermal Plant, PG&E is subject to a number of contracts, agreements, leases, and regulatory conditions that impose obligations relating to unit decommissioning or retirement. These obligations will be transferred to the purchasers of the units. The majority of decommissioning obligations arise under the steam supply agreements for both the Sonoma and Lake County units. The Sonoma County steam supply agreements with Unocal/NEC/Thermal require PG&E to dismantle and remove its facilities, clean up the facility sites, and mitigate remaining environmental hazards within a reasonable time after the facilities are dismantled and within five years after termination of the agreements through closure of the last unit. The agreements require such removal activities to be conducted in a manner that is acceptable to governmental entities having jurisdiction and consistent with applicable provisions contained in certain real property agreements between Unocal/NEC/Thermal and third parties applicable to the sites. PG&E also has land-related agreements with other parties and certain local land use permits which contain unit removal or site restoration provisions. For the Lake County units, the steam agreement with Calpine requires that PG&E sell, remove, or dispose of its facilities within a reasonable time after termination of the agreement. Other land-related agreements between PG&E and other parties also require removal of structures and site restoration. For Unit 16, the CEC has imposed Conditions of Certification that require PG&E, after operations cease, to restore the site through recontouring and revegetation, and to prepare a decommissioning plan containing biological mitigation measures.[2] Units 17, 18 and 20 are also subject to CEC oversite during decommissioning.

Some parties have expressed concern that a new owner might be more likely than PG&E to go bankrupt and abandon a power plant, leaving behind significant environmental problems and cleanup liability. An examination of the purchasers of previously divested utility plants in California shows that these companies are all large, multi-faceted, financially secure energy service companies, with bond ratings similar to or better than PG&E's. To ensure PG&E can recover its investment in the Geysers units through the sale, PG&E has a high incentive to choose a financially secure purchaser of the divested

1 *Summary of Decommissioning Requirements for PG&E's Fossil-Fueled Plants*, Prepared for PG&E by O'Melveny & Myers LLP, October 29, 1998.

2 *Summary of Decommissioning Requirements for PG&E's Geysers Geothermal Plant*, Prepared for PG&E by O'Melveny & Myers LLP, October 29, 1998.

plants, and the CPUC will not approve a purchase by a company that does not have the expertise and resources needed to responsibly operate a power plant. The EIR preparers are unaware of any company similar to the purchasers of the previously divested plants that has gone bankrupt. Rather, because these companies own very valuable assets (i.e., power plants, which provide access to the transmission grid), when one becomes even remotely financially weak, it is more likely that other companies would offer to engage in a merger or other consolidation mechanism. Conversely, at least one regulated utility and several consumer-owned cooperative utilities in the Western Unites States have gone bankrupt in recent years, leaving significant liabilities unpaid, although all of their generation assets were assumed by other entities and continue to operate.

However, even if it is assumed that the sale of the plants to a new owner would increase the risk that a plant owner would become insolvent and abandon the plant, compared to the risks posed by PG&E (a regulated utility) continuing to own the plants, there is no basis to conclude that the eventual decommissioning of the plants would be affected in a manner that would result in environmental impacts. In cases where utilities or small cogeneration plant owners have gone bankrupt in the past, their power plants have continued to operate, either under a new owner or under the supervision of a bankruptcy trustee. For the plants in question in this project, especially concerning the Bay Area fossil-fueled plants, the sites alone would have a considerable market value because they offer access to the transmission grid in areas that need power plants, meaning that as long as the sites remain viable for construction of a power plant, energy service companies will aggressively pursue the chance to obtain them. Access to the grid may prove so valuable that companies would be willing to pay for any needed decommissioning costs related to abandoned facilities on the site. In addition, as long as the present facilities remain classified as “must-run,” the ISO would offer class “C” reliability must-run agreements, which allow continued operation (and payments) even if the owner has filed for bankruptcy protection. The only way the plants that are presently designated as must-run could lose that status would be if some other facility could provide the same reliability support as the present plants. Most likely, this would involve construction of a new power plant or a new transmission line. Siting of such new facilities would require environmental review and, if it appeared that such new facilities could cause the closure of existing plants or threaten the must-run status of existing plants, those potential occurrences would be analyzed and subject to public debate. For the Geysers especially, that environmental review would include examination of the impact of replacing the generation of already viable renewable energy with energy generated elsewhere.

Even assuming that a power plant were abandoned and that no purchaser were interested in the remaining assets or the site, the potential for significant environmental impacts caused by abandonment is still very remote. As to the Geysers generating units, once the steam were shut off to the units, very little potential for environmental contamination would exist because of the relatively small amounts of toxic substances used, produced or stored at the generating units. Therefore, these facilities could remain in place indefinitely without causing significant environmental consequences. (If enough steam pressure still existed such that leaking piping systems would be a problem, then presumably enough steam pressure would still exist to generate power, making the existing assets valuable enough to attract new purchasers.) A similar situation exists for the unlikely event of abandonment of the fossil-fueled power plants, which are all securely fenced. Once the fuel were shut off to the plant, and the comparatively small amount of (still valuable) fuel oil were removed from the storage tanks, little potential would exist for ongoing environmental concerns. As well, the plant would no longer produce polluting air emissions or thermal impacts on local waterways.

Furthermore, if a power plant were abandoned, and the previous owner could not pay for cleanup and other decommissioning costs (such as was the case with the case of a Geysers steam field operator that walked away from 24 leaking wells, as detailed in the response to Comment T8), other resources are available to local agencies for any needed remediation or other decommissioning work.[3] These include EPA superfund monies and various grant programs from state and federal agencies.

Therefore, for all the reasons detailed above, implementation of the project would not result in any potentially significant environmental effects associated with decommissioning. Please also see response to Comment K1 for a discussion of the impact from decommissioning on local agencies.

B6 The DEIR has evaluated capacity factors and the resultant effects under a 2005 Analytical Maximum scenario for both the Pittsburg and Contra Costa Power Plants. In addition, the analysis includes an evaluation of the potential environmental impacts associated with operation of the proposed ENRON Pittsburg District Energy Facility (PDEF). The results of the capacity/generation analysis are available in Attachment G of the DEIR. An analysis of the potential cumulative impacts of the project with the PDEF is available in Chapter 5, Cumulative Impacts, Section 5.3.4, Cumulative Effects Under Variant 2. A detailed analysis of the potential cumulative effects of the Calpine-Pittsburg Power Plant, also referred to as the Delta Energy Center Project (DECP), together with the Pittsburg, Contra Costa and proposed PDEF plants, is provided in the response to Comment B15.

With respect to the commenter’s suggestion that the 2005 Analytical Maximum analysis should include an increase in the operations of both the Pittsburg and Contra Costa Power Plants, the maximum generation for these plants has been modeled and evaluated for a future date of 2005. It was determined that the new generation projected to become available locally and throughout the State of California would tend to lower the capacity at the plants being divested by PG&E as of 2005, including the Pittsburg and Contra Costa Power Plants.

In response to this comment and based on discussions with the CEC (Layton, 1998), it was determined that additional atmospheric dispersion modeling would be prepared for the

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3 Note that the environmental impact associated with closure of a Geysers generating unit is much less severe than that associated with closure of a steam suppliers facilities.

PG&E Pittsburg and Contra Costa Power Plants together with the proposed new PDEF. Since the newly proposed Calpine DECP has not filed an application with the CEC, insufficient information is available to include the DECP in this analysis. The commenter has also suggested that potential industrial development also be considered in this analysis. As shown on Table 5.1 of the DEIR, none of the local cumulative projects for the Pittsburg/Contra Costa area are industrial in nature and, thus, there are no known potential industrial project to consider or include in this analysis.

The CEC has supplied to the EIR preparers atmospheric dispersion model input data taken from the PDEF's permitting package recently submitted to the CEC. Such modeling data consists of model input and output of short-term and annual model analyses for PM-10 and NO_x. The CEC-supplied PDEF data has been assumed to be correct for the purposes of, and has been employed in, this analysis.

The purpose of this additional atmospheric dispersion modeling exercise was to determine, to the extent possible, what future cumulative air quality impacts could occur within the local Pittsburg-Antioch airshed from combined operation of the Pittsburg and Contra Costa Power Plants and the proposed PDEF. In order for this new analysis to be comparable with analyses already presented in the DEIR, the following parameters were followed in the modeling:

- One year of on-site meteorological data was used for modeling purposes. Since the DEIR already utilized 1994 meteorological data provided by PG&E for analysis of the Pittsburg Power Plant, the same year of meteorological data was applied jointly to all three plants.

- Only PM-10 and NO_x data were available as model inputs for the PDEF. Consequently, only PM-10 and NO_x were analyzed in the future cumulative case. Emissions of sulfur dioxide and carbon monoxide were evaluated separately for the Pittsburg and Contra Costa Power Plants; their low levels already shown in the DEIR indicate that any additional impact from the PDEF would not be expected to compromise local air quality.

- The future cumulative analysis was based on expected plant emissions for the year 2005. This year matches the same year used in the DEIR for all future cumulative analysis and furthermore is a reasonable timeframe in which the PDEF could be expected to be fully operational.

- Emissions for the Pittsburg and Contra Costa plants were based on two factors: (1) projected model emissions for annual capacity factors, as presented in the DEIR and as revised in the FEIR, including corrections for the Contra Costa plant (see response to Comment B11), were used to simulate annual emissions for these plants, and (2) projected maximum hourly emission rates were used for short-term model predictions, i.e., 1-hour and 24-hour values. It should also be noted that per the DEIR, Pittsburg Power Plants Units 3 and 4 were assumed to be decommissioned by 2005. This assumption was simulated in this modeling analysis.

- Emissions for the PDEF for both short-term and annual rates utilized data as provided from the CEC.

This analysis was conducted using the Industrial Source Complex Short Term 3 Model (ISC3), Version 97363. This model was developed and approved for use by the U.S. Environmental Protection Agency and represents the state of the art in atmospheric dispersion modeling. The model was used assuming standard regulatory default options and BAAQMD modeling guidelines.

The source parameter data for the Pittsburg and Contra Costa plants were provided by PG&E, while the PDEF parameters were provided by the CEC. Figure B6 shows the location of all three power plants and the approximate location of the unmodeled Calpine DECP. A receptor network grid of 975 individual points was used to evaluate the combined impact of all three modeled power plants. (Receptors are points where an atmospheric dispersion model predicts impacts from pollution sources being simulated by the model.) This receptor grid was 22.5 kilometers (14 miles) in the west-to-east direction by 6.5 kilometers (4 miles) in the north-to-south direction and was oriented so that all three power plants were located within the central portion of this region and all were a minimum of about 5 kilometers (3.1 miles) from either the east or west edge of the impact region. This grid provided adequate coverage of the local population areas of Pittsburg and Antioch. Receptor grid spacing was typically 500 meters (0.31 miles), except for the grid placed over the City of Pittsburg, where spacing was 250 meters (0.16 miles). Added to the receptor modeling grid were the locations of sensitive receptors close to both the Pittsburg and Contra Costa Power Plants, as identified by PG&E. In the case of Pittsburg Power Plant, this same set of sensitive receptors was used to evaluate local air quality impacts for the DEIR. Since each plant was analyzed separately in the DEIR, receptor points were not located within the physical plant boundary. When the three power plants were combined for this analysis, some receptors, as located on the regularly spaced grid, fell within plant boundaries. For the purpose of this conservative analysis, no attempt was made to exclude these in-plant receptors. This technique allowed for examination of combined impacts from two different plant operators (e.g., PG&E and ENRON) on each other's property.

The results of the modeling analysis are presented in Table B6-1. The concentrations shown on the table represent the maximum concentrations for PM-10 and NO_x for short-term and long-term periods for all power plants combined and for each power plant's stand-alone point of maximum concentration. For both the PM-10 and NO_x analyses, the maximum impact point are identical and occur at a point approximately 450 meters southeast of Pittsburg Power Plant's Unit 1. This same point is also the point of maximum concentration for PM-10 and NO_x for the Pittsburg Power Plant alone. For the PDEF, the points of maximum concentration are located as follows: for PM-10 short-term, the maximum concentration is located approximately 800 meters east-southeast of the PDEF, the short-term NO_x maximum occurs at approximately 3.5 kilometers southwest of the PDEF, and the annual PM-10 and NO_x maximums occur between 700 to 800 meters east

INSERT FIGURE B6

Click on this box to display Figure B6

LOCATION OF THE PITTSBURG, CONTRA COSTA, AND PROPOSED ENRON AND CALPINE POWER PLANTS

TABLE B6-1
SUMMARY OF FUTURE CUMULATIVE AIR QUALITY AT MAXIMUM RECEPTOR POINTS FOR PG&E PLANTS AND PROPOSED ENRON POWER PLANT IN 2005

Pollutant/ Time Period	Combined Impact (µg/m3)	Pittsburg Only (µg/m3)	PDEF Only (µg/m3)	Contra Costa Only (µg/m3)
PM-10 / 24-hr	10.96	10.96	2.18	7.87
PM-10 / Annual	1.73	1.68	0.38	1.28
NO_2 / 1-hr	271.4	271.4	16.3	61.1
NO_2 / Annual	16.0	15.9	0.64	2.06

NOTE: The concentrations shown on this table are shown for the respective points of maximum impact. For each value shown, these points are not necessarily located at the same location. Locations of these points are discussed in the text of this response.

of the PDEF. For the Contra Costa plant, the points of maximum concentration for PM-10 and NO_x, both short and long-term, all coincide on the Contra Costa Power Plant fenceline's northeast corner.

To clearly depict each individual plant's contribution to the combined impact, Table B6-2 presents the model-predicted concentrations for each individual plant at the combined point of maximum concentration. As may be seen, for both the 24-hour PM-10 and the 1-hour NO_x concentrations, all of the combined impact results from Pittsburg Power Plant emissions (24- and 1-hour values shown for PDEF and Contra Costa represent the maximum model-predicted concentration for the entire year of modeling data and do not occur at the same time the maximum combined impact occurs). For the annual PM-10 and NO_x impacts, Pittsburg contributes nearly all of the maximum combined values, while the PDEF and Contra Costa plants contribute only a few percent to the maximums on the table.

The results of this analysis show that for the future cumulative case in 2005, combined air quality impact results for PM-10 and NO_x are dominated by the Pittsburg Power Plant. While there is some interaction of air quality impacts between the Pittsburg plant and the PDEF, the Contra Costa Power Plant, located about six miles east of the PDEF, is far enough away from both the Pittsburg plant and the PDEF that contributions from the Contra Costa plant are insignificant within the other two plants' impact areas. The combined impacts presented in Table B6-1, although occurring at a slightly different location than those presented on revised Tables 4.5-31 and 4.5-32 (see response to Comment B11), are quite similar in magnitude and still represent a less-than-significant impact.

TABLE B6-2
INDIVIDUAL PLANT CONTRIBUTIONS AT FUTURE CUMULATIVE CASE COMBINED IMPACT POINT OF MAXIMUM CONCENTRATION

Pollutant/ Time Period	Combined Impact (µg/m3)	Pittsburg Contribution (µg/m3)	PDEF Contribution (µg/m3)	Contra Costa Contribution (µg/m3)
PM-10 / 24-hr	10.96	10.96	0.58	0.46
PM-10 / Annual	1.73	1.68	0.035	0.022
NO_2 / 1-hr	271.4	271.4	6.25	12.78
NO_2 / Annual	16.0	15.93	0.057	0.036

NOTE: The combined impact point of point of maximum is located on the PG&E Pittsburg Power Plant fenceline just east-northeast of Pittsburg Unit 1.

As a consequence of the results from the future cumulative 2005 case discussed above, the corresponding health risk assessment was updated to include a more detailed evaluation of the combined health risk in 2005 from all three power plants. Table B6-3 identifies the combined health risks for the PG&E power plants and the proposed PDEF plant at the cumulative maximum receptor under the 2005 Cumulative A-Max scenario. The table shows that the maximum cancer risk is estimated to be 0.62 in a million, which is less than the significance threshold of 10 in a million. Note that the major contribution to the maximum receptor is from the PDEF and that the relative contributions to health risks of the three plants are different than the local air quality impacts shown on Tables B6-1 and B6-2. Although this analysis is limited in scope, from data supplied by the CEC, it appears that while emissions of criteria pollutants from the PDEF are less than either the Pittsburg or the Contra Costa plants, emissions from the PDEF's cooling towers are greater contributors to health risks than at the other two plants. The table also shows that the maximum chronic and acute hazardous indices from the combined plants are below the significance threshold of 1.0. Therefore, cumulative health risks would be less than significant.

Reference:

Layton, Matt, California Energy Commission, telephone communications, October 1998.

B7 The sentence referenced in the comment is an extremely condensed summary of the lengthy agreement between Thermal Power Company and PG&E for the provision of steam by the former to the latter. "Quantities of contaminants" generally refers to impurities in the geothermal steam. Such impurities can include liquid water,

TABLE B6-3
SUMMARY OF CUMULATIVE HEALTH RISKS AT MAXIMUM RECEPTOR FOR PG&E PLANTS AND PROPOSED ENRON POWER PLANT IN 2005

Plant	Cancer Risk[a] (in a million)	Chronic Hazard Index[b]	Acute Hazard Index[b]
Contra Costa[c]	0.00	0.00	0.02
Pittsburg[c]	0.02	0.002	0.01
PDEF	0.60	0.04	0.034
Total	0.60	0.042	0.064

[a] The significance threshold for incremental cancer risk is 10 in a million, based on BAAQMD Guidelines.
[b] Hazard index is the ratio of the maximum exposure level and the reference dose of each toxic substance. The reference dose is the level with no observed health effect. A hazard index less than 1.0 indicates no health effect.
[c] Cancer risks and Hazard Indices are based on the results reported in Pacific Gas and Electric Company Air Toxics Hot Spots Risk Assessments (1993), adjusted to future emissions.

particulates, settleable solids, and noncondensable gases. Examples can include hydrogen sulfide, chlorides, boron, and amorphous silica. Thermal Power Company has an obligation, set forth in the agreement, to provide PG&E with steam that meets certain steam quality standards, including limitations on the contaminants described above. It should also be noted that contaminant levels are limited by various government regulations.

B8 Please see response to Comment B5.

B9 Page 2-6 of the DEIR is hereby amended (first paragraph under Geysers Power Plant heading, second sentence) by the addition of the following footnote to the end of the sentence:

> The CEC certified Units 16, 17, 18, and 20 for construction and operation. Under Section 1769 of its Power Plant Site Certification Regulations, the CEC must approve any change in ownership of these units. Any new owner will be expected to comply with all existing conditions of certification, including decommissioning. Any new owner of these units must petition the CEC for authority to transfer ownership or operational control of each unit. The petition must contain: a discussion of any significant changes in the operational relationship between the owner and operator; a statement identifying the party responsible for compliance with the CEC's conditions of certification; and, a statement that the new owner understands the conditions of certification and agrees to comply with those conditions.

B10 PG&E's latest resource planning prior to the advent of restructuring indicated that PG&E would retire all four of the small, 160 MW class Pittsburg units, i.e., Units 1 through 4 (PG&E PEA Appendix B, Table B-2, page B-20), by 2002. The old age and commensurate high operating costs of the units was a consideration in PG&E's planning, as was the projected expense of installing sufficient nitrogen oxide (NO_x) abatement equipment to comply with the Bay Area Air Quality Management District (BAAQMD) NO_x emission standards that will become more stringent, down to a level of 0.018 lb/MWh by 2005 averaged over all of the Bay Area electric power generating steam boilers. Presuming the BAAQMD revises its rules applicable to NO_x emission limits at Bay Area power plants, as expected (and/or with implementation of Mitigation Measure 4.5-5), the new owner could face the obligation of meeting emissions limits at each individual plant and, thus, could face an even stronger incentive to retire the units.

Any owner would also face the prospect of even more extensive operational limitations associated with protection of the endangered fish species. The retirement incentive discussed above would be augmented by the expected imminent extension of the operational limits to cover an additional three months of each year during which Pittsburg Unit 7 must be dispatched fully before any of the other units at the Pittsburg or Contra Costa plants can be dispatched above their minimum operating levels. Such operating constraints would further increase the cost of retaining the 160 MW units.

Even though PG&E's resource planning indicated that PG&E would retire all of Pittsburg Units 1 through 4, and despite the considerations outlined above, the EIR assumes that only Units 3 and 4 would be retired. This is because Units 1 and 2 are connected to the PG&E 115 kV system and are instrumental in assuring adequate service at that voltage level. Consequently, the ISO is expected to call upon these units in their Must Run status so frequently that either PG&E or the new owner would have a strong financial incentive to retain those units in spite of the factors mentioned above. SERASYM™ modeling assumed for each of the 1999 scenarios that all of Pittsburg Units 1 through 4 would be operational. This assumption is consistent with information provided in PG&E's PEA. In 2005, SERASYM™ modeling for the 2005 Cumulative Analytical Maximum scenario (the proposed project in conjunction with other reasonable foreseeable projects) and the 2005 Alternative 1 scenario (No Project) assumed that Units 1 and 2 would remain operational, while Units 3 and 4 would be retired. The 2005 modeling results for these scenarios are presented in Table 6.1 on page 6-7 of the DEIR. These 2005 modeling assumptions are in part consistent with information provided in PG&E's PEA, but reflect more recent systems planning review efforts by the EIR preparers that show financial incentives for PG&E or a new owner to continue operation of Units 1 and 2. Modeling results for 2005 concluded that the owner of the Pittsburg plant could comply with NO_x standards by installing a selective catalytic reduction (SCR) unit in only one of Pittsburg Units 1 or 2, providing that Units 3 and 4 were retired. Other analyses suggested that retention of either Unit 3 or 4 would require retrofitting the retained unit with SCR for NO_x reduction. The analysis showed that such expensive retrofitting is unlikely because of the age of Units 3 and 4 and the low levels of operations resulting from their inefficient operation, assuming continuation of minimum variable operating cost commitment/dispatch of the California grid.

Even if a new buyer were to retain these units (which appears unlikely), such a decision would necessitate extensive pollution equipment retrofit, substantially reducing any potential incremental emissions resulting from retention of one or both of Units 3 and 4.

B11 The DEIR reported a violation of the state 1-hour nitrogen dioxide standard from emissions at the Pittsburg plant, because a very conservative approach was used to predict maximum levels, although it is stated in the DEIR that the impact is highly unlikely. Subsequent to publication of the DEIR, a more refined analysis was carried out to estimate the maximum 1-hour nitrogen dioxide concentrations from both the Contra Costa and Pittsburg plants. Using new simultaneous measurements of nitrogen dioxide and ozone in the ozone limiting method, the revised predicted maximum level from Pittsburg plant emissions together with projected background levels, is estimated to be 396 $\mu g/m^3$, which is below the state standard of 470 $\mu g/m^3$. The last paragraph on page 4.5-67 of the DEIR is removed as follows:

> ~~The modeling results in Table 4.5-32 show that the maximum one hour average concentration of nitrogen dioxide may exceed the state standard under both the 1999 baseline conditions and under the 1999 Analytical Maximum scenario. The estimated maximum concentrations for both scenarios incorporate extremely conservative background conditions. For the worst case modeling analysis, it is assumed that the highest background levels for nitrogen dioxide and ozone occur simultaneously at the same location. The background levels for these pollutants directly affect the magnitude of the estimated one-hour nitrogen dioxide total concentration. Since it is highly unlikely that the maximum background levels occur simultaneously, it can be assumed that the state one-hour standard will not be exceeded. It should be noted that the maximum 1-hour concentration is predicted to be the same, with or without the project.~~

Table 4.5-32 is hereby amended as shown in this response.

In addition to the preceding changes to the text, NO_x values for the Contra Costa Power Plant were also corrected for the more refined ozone limiting analysis. Additionally, after the DEIR was published, it was discovered that corrections were needed to the 1- and 8-hour carbon monoxide, 24-hour PM-10, 1-hour NO_x, and 1- and 24-hour sulfur dioxide concentrations presented on Table 4.5-31. These corrections all resulted in increased model-predicted short-term concentrations for the Contra Costa Power Plant. Although these corrections indicate increased concentrations, none of the corrections change the conclusion that local impacts are less than significant. The first two paragraphs of text on page 4.5-67 of the DEIR are hereby amended to read as follows:

TABLE 4.5-32
PITTSBURG POWER PLANT CONCENTRATION ESTIMATES[a]

		Concentrations in Micrograms per Cubic Meter (µg/m³)			Power Plant Effect/Total Concentration[b]				
Pollutant	**Averaging Period**	**State Standard**	**National Standard**	**Delta Region Background**	**1999 Baseline**	**1999 Analytical Maximum**	**2005 Cumulative Analytical Maximum[d]**	**Difference between 1999 Analytical Maximum and Baseline**	**Difference between 2005 Cumulative Analytical Maximum and Baseline**
Carbon Monoxide	1 hour	23,000	40,000	6,517	551.6/7,068	551.6/7,068	288.2/6,805	0	-263
	8 hours	10,000	10,000	3,297	432.2/3,729	432.2/3,729	226/3,523	0	-206
Nitrogen Dioxide	1 hour[c]	470	NA	<u>38</u> ~~132~~	<u>358/396</u> ~~350.5/**483**~~	<u>358/396</u> ~~350.5/**483**~~	<u>262/300</u> ~~262/394~~	0	-<u>96</u> ~~89~~
	annual	NA	100	31	20.0/51	46.1/77	9.3/40.3	26.1	-10.7
Sulfur Dioxide	1 hour	655	NA	87	3.9/90.9	3.9/90.9	2.1/89.1	0	-1.8
	24 hours	105	365	24	1.6/25.6	1.6/25.6	0.8/24.8	0	-0.8
	annual	NA	80	3	0.14/3.1	0.3/3.3	0.13/3.1	0	-.01
Particulate Matter (PM-10)	24 hours	50	150	**60**	12.3/**72.3**	15.9/**75.9**	7.4/**67.4**	3.6	-4.9
	annual	30	50	22	1.1/23.1	2.2/24.2	1.0/23	1.1	-0.1
Particulate Matter (PM-2.5)	24 hours	NA	65	ND	<u>12.3/ND</u> ~~12.3/12.3~~	<u>15.9/ND</u> ~~15.9/15.9~~	<u>7.4/ND</u> ~~7.4/7.4~~	3.6	-4.9
	annual	NA	15	ND	<u>1.1/ND</u> ~~1.1/1.1~~	<u>2.2/ND</u> ~~2.2/2.2~~	<u>1.0/ND</u> ~~1.0/1.0~~	1	-0.1

a The maximum receptor is approximately 0.3 miles east of the plant. Background concentrations (except for annual averages) represent the average of the 2nd highest values recorded each year from 1994 to 1996 at the Bethel Island monitoring station.

b In these columns, the number on the left shows the contributions of the power plants; the number on the right is the total contribution, including the Delta Region background.

c Maximum NO_2 concentrations from the power plant were calculated using the Ozone Limiting Method (Cole and Summerhays, 1979) based on a worst-case <u>simultaneous background concentration of nitrogen dioxide and ozone of 38 and 243 µg/m³, respectively</u> ~~background ozone concentration of 133 micrograms per cubic meter~~.

d The 2005 Cumulative Analytical Maximum assumes new owners will have to comply with a modified BAAQMD Regulation 9, Rule 11 emission rate schedule similar to the existing schedule.

NA: Not applicable

ND: Not determined; PM-2.5 ambient monitoring has only recently begun in the Bay Area.
Values shown in bold type exceed a corresponding ambient air quality standard.

With regard to the potential short-term impacts on respiratory effects, the estimated maximum 24-hour average contribution from the plant (with or without divestiture) is estimated to be ~~less than 3~~ 6.7 μg/m^3 (Table 4.5-31), which is well below the 20 μg/m^3 concentration threshold that may cause increased respiratory problems.

For chronic exposure to PM-10, the estimated maximum annual average contribution from the plant was shown in Table 4.5-31 to be ~~less than 3~~ 6.7 μg/m^3, which is below the significance threshold of 10 μg/m^3.

Table 4.5-31 of the DEIR is hereby amended as shown in this response.

The commenter expresses concern that the existing emissions of the Pittsburg plant may have been double counted in the analysis. The methods used to estimate total concentrations, including background levels, are consistent with conservative approaches that are commonly used for air quality analyses, even though a portion of the measured background levels may include existing plant emissions. This approach is followed because there is considerable uncertainty in how much of the background is actually contributed by the existing plant. When the maximum background levels exceeded the ambient air standard, more restrictive thresholds, described in significance criteria 2 on page 4.5-50 of the DEIR, were used to test for significance from project impacts.

As to the adequacy of the background data, the text on page 4.5-32 gives an explanation of the rationale for using measured data at Bethel Island as being representative of levels in the Delta. The text states that measured pollutant levels at this station reflect local pollutant sources as well as sources to the west and south, because the prevailing winds transport pollutants to the Delta region. Since this is the only station with adequate data for the region, and because pollutants such as PM-10 and ozone have usually been shown to be regional in nature, the measured levels at Bethel Island were considered to be representative.

Finally, the commenter requests that the EIR address overlapping impacts from both the Contra Costa and Pittsburg plants. An additional 2005 cumulative dispersion modeling study was carried out that includes emissions from the Contra Costa and Pittsburg plants, as well as the proposed Enron plant has been conducted. The results of this cumulative modeling analysis are discussed in response to Comment B6.

B12 Contributions of the Hunters Point plant are included in the existing maximum background levels that were added to the Potrero plant's contribution in the analysis. The monitoring station on Arkansas Street is near both plants and is representative of ambient air levels for the region. Because the same maximum background levels are used in future years, when the Hunters Point plant will actually be shut down, the background levels that are used in the impacts analysis may be conservatively high.

TABLE 4.5-31
CONTRA COSTA POWER PLANT CONCENTRATION ESTIMATES[a]

Pollutant	Averaging Period	State Standard	National Standard	Delta Region Background	1999 Baseline	1999 Analytical Maximum	2005 Cumulative Analytical Maximum[d]	Difference between 1999 Analytical Maximum and Baseline	Difference between 2005 Cumulative Analytical Maximum and Baseline
		Concentrations in Micrograms per Cubic Meter ($\mu g/m^3$)			Power Plant Effect/Total Concentration[b]				
Carbon Monoxide	1 hour	23,000	40,000	6,517	184.6/6702 ~~81.1/6,598~~	184.6/6702 ~~81.1/6,598~~	184.6/6702 ~~81.1/6,598~~	0	0
	8 hours	10,000	10,000	3,297	129.2/3426 ~~56.7/3,354~~	129.2/3426 ~~56.7/3,354~~	129.2/3426 ~~56.7/3,354~~	0	0
Nitrogen Dioxide	1 hour[c]	470	NA	38 ~~132~~	272/310 ~~135.4/267~~	272/310 ~~135.4/267~~	40.4/78 ~~17.7/150~~	0	-232 ~~117.7~~
	annual	NA	100	31	11.8/43	24.6/56	3.7/35	12.8	-8.1
Sulfur Dioxide	1 hour	655	NA	87	1.3 ~~0.6~~/88	1.3 ~~0.6~~/88	1.3 ~~0.6~~/88	0	0
	24 hours	105	365	24	0.5 ~~0.2~~/24	0.5 ~~0.2~~/24	0.5 ~~0.2~~/24	0	0
	annual	NA	80	3	0.2/3.2	0.3/3.3	0.3/3.3	0.1	0.1
Particulate Matter (PM-10)	24 hours	50	150	**60**	6.7/**66.7** ~~2.9/**62.9**~~	6.7/**66.7** ~~2.9/**62.9**~~	6.7/**66.7** ~~2.9/**62.9**~~	0	0
	annual	30	50	22	1.3/23.3	2.6/24.6	2.3/24.3	1.3	1
Particulate Matter (PM-2.5)	24 hours	NA	65	ND	6.7/ND ~~2.9/2.9~~	6.7/ND ~~2.9/2.9~~	6.7/ND ~~2.9/2.9~~	0	0
	annual	NA	15	ND	1.3/ND	2.6/ND	2.3/ND	1.3	1

a Maximum contributions have been combined from the two units. No offsite location would reach these levels. Background concentrations (except for annual averages) represent the average of the 2nd highest values recorded each year from 1994 to 1996 at the Bethel Island monitoring station.

b In these columns, the number on the left shows the contributions of the power plants; the number on the right is the total contribution, including the Delta Region background.

c Maximum NO2 concentrations from the power plant were calculated using the Ozone Limiting Method (Cole and Summerhays, 1979) based on a worst-case simultaneous background concentration of nitrogen dioxide and ozone of 38 and 243 µg/m3, respectively ~~background ozone concentration of 133 micrograms per cubic meter~~.

d The 2005 Cumulative Analytical Maximum assumes new owners will have to comply with a modified BAAQMD Regulation 9, Rule 11 emission rate schedule similar to the existing schedule.

NA: Not applicable

ND: Not determined; PM-2.5 ambient monitoring has only recently begun in the Bay Area.

Values shown in bold type exceed a corresponding ambient air quality standard.

B13 Page 4.8-1 of the DEIR (paragraph 2) is hereby revised to reflect the most recent energy consumption figures, as follows:

> The major users of electricity are industry, 22 percent; commercial, 35 percent; ~~13 percent; industrial, 10 percent; and~~ residential, 30 percent; ~~10 percent~~ agriculture, 7 percent; and other, 6 percent.

B14 While the analysis presented in Attachment C of the DEIR illustrates that contractual requirements, market forces, operating constraints, portfolio size, company financial characteristics, and other factors would affect the rate at which divested power plants are operated by new owners, a strong economic disincentive for inefficient use of nonrenewable energy resources would always be present, due to the simple fact that the more such resources are consumed by a plant owner, the more that owner would pay, thus reducing potential profits. Similarly, it is likely that more efficient plants would be better able to provide power at a lower price than less efficient plants and thus would not be displaced by less efficient plants.

The question of whether increased fossil-fueled generation resulting from divestiture would displace cleaner/renewable power is an important one however. It is noted that the Analytical Maximum scenario in the DEIR, which forecasts increased generation at the fossil-fueled plants, is an extremely conservative scenario and that actual increases in generation resulting from divestiture would likely be less. It is also noted that power plants designated as qualifying facilities under the Public Utilities Regulatory Powers Act (PURPA) having met fuel-type, efficiency, and other standards) were able to enter must-take contracts with local utilities, and thus would not be displaced by increased fossil-fueled generation. Finally, as noted on page 3-7 of the DEIR, physical and operational differences between restructuring with the proposed divestiture and without divestiture will, as a practical matter, be temporary. This is true because the utilities' fossil plants must be market-valued (sometime before 2002), and as of March 31, 2002, PG&E could participate in the direct access market.

B15 The information provided by the commenter was unavailable at the time the DEIR was published. The information provided in Section 5.2.2 of the DEIR was obtained from CEC staff and was gathered after the Notice of Preparation was circulated. However, in order to incorporate the updated information provided by the commenter and obtained from Robert Haussler of the CEC during a telephone conversation on November 3, 1998, the following text changes have been made to the DEIR.

The second sentence of the last bullet on page 5-5 of the DEIR has been modified as follows:

> The plant would be a merchant power plant with a generating capacity of roughly 1,050 MW ~~range of 660 to 700 MW~~ to be located in southern San Diego County near the California-Mexico border.

The last sentence of the last bullet on page 5-5 of the DEIR has been replaced with the following text:

> The CEC expects the AFC to be filed in January 1999.

The last sentence of the second to last bullet on page 5-6 of the DEIR has been modified as follows:

> The project applicant plans to file its AFC in 1999 ~~the fall of 1998~~.

The last sentence of the last bulleted item on page 5-6 of the DEIR is hereby amended as follows:

> The project applicant filed ~~plans to file~~ its AFC on August 12, ~~during the summer of~~ 1998, which was later deemed complete by the CEC on August 26, 1998.

The following bulleted items are added at the end of the list of potential power plant siting cases in California on page 5-6 of the DEIR.

- The Sunrise Cogeneration and Power Project is proposed by Texaco Global Gas and Power. The proposed cogeneration facility would include two gas turbines and two heat recovery steam generators. The facility would have a nominal capacity of 340 MW. The facility would be located in an active oil field approximately three miles northeast of Fellows in western Kern County. The CEC expects the AFC to be filed prior to the end of 1998.

- The Long Beach District Energy Facility is proposed by Enron. The proposed cogeneration facility would include natural gas fired combustion turbines and would have a nominal capacity of 500 MW. The facility would be located on the Port of Long Beach in Los Angeles County. The CEC expects the AFC to be filed in 1999.

- The Delta Energy Center Project (DECP), also known as the Calpine Pittsburg Project, is proposed by a joint venture of Calpine Corporation and Bechtel Enterprises. The facility would have a generating capacity of 535 to 800 MW. The facility would be located at the Dow Chemical site in the City of Pittsburg. The CEC expects the AFC to be filed prior to the end of 1998.

- The Elk Hills Power Project is proposed by Sempra Energy Resources and Occidental Energy Ventures Corporation. The plant would be a 500 MW natural gas-fired, combined-cycle facility located approximately 35 miles west of Bakersfield at the Elk Hills Naval Petroleum Reserve. The proposed site is owned by Occidental of Elk Hills, Inc. The project applicant plans to file its AFC in early 1999.

- The Three Mountain Power Project is proposed by Three Mountain Power, LLC (Ogden Pacific Power) of Redding. The proposed facility would be a 500 MW natural gas-fired, combined-cycle power plant, consisting of two advanced technology combustion turbines, one or more steam turbines, and supporting equipment. The facility would be built adjacent to an existing 10 MW waste wood-fueled power plant at Tiker Mountain near Burney, California. The proposed facility would connect to existing PG&E 230 kV transmission lines located near the project site. The CEC expects the AFC to be filed in February 1999.

- The Blythe Energy Power Plant Project is proposed by Blythe Energy, LLC. The proposed facility would be a 400 MW base-loaded, combined-cycle power plant. The facility would be located in the City of Blythe, near the Arizona border. The project applicant plans to file its AFC in early 1999.

The first sentence of the last paragraph on page 5-6 of the DEIR has been revised as follows:

> A number of other merchant power plants are being considered for development in California, including the repowering of several coastal natural gas-fired power plants (Haussler, 1998)~~four recently identified power plants in the Bay Area proposed by Calpine Corporation and a unit of Bechtel Group (Howe, 1998)~~.

Though not specifically identified in the DEIR originally, the expected operational impacts of the Sunrise Cogeneration and Power Project, the Long Beach District Energy Facility, the Elk Hills Power Project, the Three Mountain Power Project and the Blythe Energy Project are considered in the overall discussion of cumulative impacts in Chapter 5 of the DEIR. Please see the response to Comment F57 for a detailed discussion of why these power plants, even if information was available prior to publication of the DEIR, would have been excluded from the detailed cumulative modeling and analysis. Similar to the other potential power plants identified in Section 5.2.2 of the DEIR, but not carried forward into the detailed cumulative analysis, these plants are geographically located at a considerable distance from the power plants being divested by PG&E and would not result in localized cumulative impacts. In summary, the inclusion of these power plants would not affect the conclusions in the DEIR regarding the level of significance of cumulative impacts.

Based on the proximity of the above-described DECP to both the existing Pittsburg and Contra Costa Power Plants and the proposed Pittsburg District Energy Facility (PDEF) (described on page 5-5 of the DEIR), a discussion of the potential for localized cumulative impacts to occur is germane. To the extent that information is available, the analysis below focuses on the potential for the addition of the DECP in the Bay-Delta region to affect the conclusions of the analysis completed for the cumulative Variant 2 scenario in Section 5.3.4 (pages 5-39 to 5-42), which considers the effects of the PDEF in conjunction with divestiture and other cumulative projects. When further defined, the DECP would be subject to separate environmental review and permitting by the CEC and other agencies with jurisdiction over the plant's operations.

The addition of the DECP to the Variant 2 scenario would be expected to further drive down the annual plant capacity factors at each of the plants being divested, when compared to the 2005 Cumulative Analytical Maximum scenario considered in Section

5.3.2. Similarly, it is expected that operation of the DECP would decrease the annual plant capacity factor of the PDEF from what is shown in Table 5.2 on page 5-17 of the DEIR. Based on this reduction in generation, any impacts that could occur in the immediate vicinity of the plants being divested would be lessened further by the operation of the DECP. However, like in the case of the PDEF, construction and operation of the proposed DECP would have its own localized impacts and could result in some regional impacts in combination with the plants being divested.

Generally speaking, the localized impacts identified in Section 5.3.4 would be incrementally greater with the addition of the DECP to the Bay-Delta region. The inclusion of the DECP would not, however, alter the conclusions in the DEIR.

Operation of the DECP would increase the potential to adversely affect water resources in the Bay-Delta by incrementally increasing the potential for discharge impacts to marine water quality to occur beyond that identified for the cumulative Variant 2 scenario (see the response to Comment O3). This would still be considered a potentially significant cumulative impact on water resources, regardless of whether or not cooling towers were used at the DECP. Because the DECP would be subject to the same National Pollution Discharge Elimination System (NPDES) permitting process as was described for the PDEF, it is expected that any significant cumulative impact on water resources could be mitigated to a less than significant level.

The NPDES permit for the DECP would also be designed to protect the aquatic resources of the Bay-Delta. The addition of the DECP would also incrementally increase the total amount of water intake structures in the area, thereby increasing the potential for entrainment and impingement of sensitive aquatic resources during cooling water intake beyond that identified for the cumulative Variant 2 scenario. Because the four Delta plants (the DECP, the PDEF, and the Contra Costa and Pittsburg Power Plants) would likely be owned by three separate entities (Pittsburg District Energy, LLC, the joint venture of Calpine Corporation and Bechtel Enterprises, and the new owner of the Contra Costa and Pittsburg Power Plants) rather than only two separate entities, the coordination of power plant operations would be even more difficult and unlikely. Similar to the conclusions of the Variant 2 analysis, this would be cumulative impact on biological resources unless mitigated by similar measures as those recommended for the PDEF in the DEIR.

With respect to air quality, the addition of the DECP to the cumulative Variant 2 scenario could incrementally increase the potential for adverse air quality effects in the San Francisco Bay area to occur at both a local and regional level. Like the PDEF, the proposed plant would likely result in a minimal increase in employment levels (less than 100 persons). The commensurate increase in traffic and associated criteria air pollutant emissions would also be minimal and in combination with the PDEF and other projects, would not result in any cumulatively considerable emissions of criteria air pollutants. The main issue of concern would still relate to the stationary source emissions associated with the power generation process at the new plant.

The DEIR concludes that at a regional level, emissions of each criteria pollutant, except PM-10, would decrease under the Variant 2 scenario, when compared to the 2005 Cumulative Analytical Maximum. Subsequent analysis (see the responses to Comments O4 and U14) shows that PM-10 emissions would increase in 2005 by an estimated 9 tons per year regionally with the new PDEF, rather than the 20 tons per year cited in the DEIR. It is further concluded that there would be a net decrease in Bay Area power plant emissions of PM-10 and PM-10 precursors under Variant 2 in 2005 compared to 1999 baseline conditions. Therefore, Bay Area power plant emissions would not contribute to the cumulative effect of increased emissions from new development in the Bay Area on regional PM-10 concentrations.

Using these same concepts, ozone and PM-10 precursor emissions estimates were made for the DECP by adjusting the estimated emissions for the PDEF based on plant capacity (800 MW versus 480 MW). These estimates assume that the DECP would employ similar control technologies to those assumed for the PDEF and would therefore have similar pollutant emission characteristics. These estimates may overstate the emissions from the DECP, since the plant may be only 535 MW in size. By adding the DECP to the Variant 2 scenario, Bay Area power plants would emit approximately 790 tons per year of ROG and 1,380 tons per year of NO_x in 2005. The change in power plant emissions relative to the 1999 Baseline scenario would be an increase of ROG emissions of 369 tons per year and a decrease in NO_x emissions of 2,930 tons per year. The net change would therefore be negative as the decrease in NO_x emissions would more than offset the increase in ROG emissions. As such, even with the addition of the DECP, Bay Area power plants would not contribute to the cumulative effect of increased emissions of ozone precursors from new development in the Bay Area on regional ozone concentrations.

Furthermore, by adding the DECP to the Variant 2 scenario, it was estimated that Bay Area power plants would emit approximately 826 tons per year of direct PM-10 emissions in 2005. Secondary sources of PM-10, ROG, NO_x, and SO_x, would emit approximately 33, 230, and 14 tons per year, respectively. The change in power plant emissions relative to the 1999 Baseline scenario would be an increase of ROG, SO_x, and PM-10 emissions of 15, 7, and 444 tons per year, respectively, and a decrease in NO_x precursor emissions of 489 tons per year. The net change would therefore be negative as the decrease in NO_x emissions would offset the increase in PM-10, ROG, and SO_x emissions. As such, even with the addition of the DECP, Bay Area power plants would not contribute to the cumulative effect of increased emissions of PM-10 and PM-10 precursors from new development in the Bay Area on regional PM-10 concentrations.

Similar to the PDEF in Variant 2, operation of the new DECP could adversely affect air quality at the local level. Emissions of criteria air pollutants and toxic air contaminants that could potentially increase overall health risks would be incrementally higher than under Variant 2 alone. This would still be a potentially significant cumulative effect on local air quality. However, the DECP, like the PDEF, would be subject to separate project-specific environmental review and permitting by the CEC and other agencies with jurisdiction over the plants operation (including the BAAQMD), at which time the potential for these impacts to occur would be fully evaluated. Therefore, it is assumed that any significant impact on local concentrations of criteria air pollutants and toxic air contaminants associated with the new DECP would be mitigated to a less than significant level. It has also been assumed that the combined emissions from the Pittsburg and Contra Costa Power Plants and the new PDEF would be minimal relative to ambient concentrations associated with mobile sources. It is likely that the addition of the new DECP would not change this assumption. In light of the low health risks associated with the operation of the Pittsburg and Contra Costa Power Plants and the permitting process that would apply to both the new PDEF and the DECP, any localized significant cumulative air quality impacts could be mitigated to a less than significant level.

The inclusion of the DECP to the Variant 2 scenario would not affect the conclusions on pages 5-41 and 5-42 regarding consistency with the *'97 Clean Air Plan*.

B16 As described on page 5-16 of the DEIR, the cumulative impact discussion in Section 5.3.2 (pages 5-20 to 5-38) addresses the potential cumulative effects of PG&E's proposed divestiture in combination with reasonably foreseeable projects identified in Section 5.2 (including a new 480 MW power plant in San Francisco, other potential future power plant projects, transmission line projects, and wastewater injection projects). (See the response to Comment F57 for a discussion of why certain cumulative projects were not carried forward into the detailed cumulative modeling and analysis.) The analysis in Section 5.3.2 also takes into account the local cumulative projects identified in Table 5.1 of the DEIR. The Variant 1 (pages 5-38 to 5-39) and Variant 2 (pages 5-39 to 5-42) analyses are based on the impact discussion in Section 5.3.2 and focus on how the potential for cumulative effects to occur may vary if a combination of new generation and transmission to replace the Hunters Point Power Plant (Variant 1) or the new PDEF (Variant 2) were added to the mix of cumulative projects being considered.

Please see response to Comment B15 above for a discussion of impacts associated with the DECP in combination with Variant 2. See response to comment B6 for air dispersion cumulative impacts for the Pittsburg, Contra Costa, and PDEF plants.

B17 The commenter is correct that the nominal rating of the PDEF is 500 MW. However, it is the understanding of the DEIR preparers that the "net" capacity of the PDEF is 450 MW. Net capacity is the amount of power a generating unit can put into the electric grid. A plant's net generating capacity is equal to the rated generating capacity of the generators in the plant minus the amount of power needed for the various electric components of the plant, such as pumps and heaters. In the case of the PDEF, this difference is 50 MW. Net capacities were used in this DEIR because it is the net capacity that is simulated and analyzed in the electric dispatch modeling (see Attachments C and G of the DEIR). Thus, no change is needed in Table 5.2 or other similar references throughout the DEIR.

B18 The CEC's final staff report cited in the comment was not available at the time of publication of the DEIR. According to the principal author and project manager of the report, the final document essentially constituted a management approval of the draft report cited in the DEIR, and nothing substantial was changed.[4] *1998 Baseline Energy Outlook* contains energy consumption projections for 1995 to 2007. In the draft document, historical data was used through 1996, while in the final document, historical data was included for 1997 as well. With the exception of San Diego County, the actual data was very similar to the 1997 projections contained in the draft *Outlook* document. San Diego County consumption in 1997 was higher than anticipated due to hotter-than-normal weather and higher industrial consumption resulting from the unusually robust economy. However, there was insufficient time to run the forecast models again with the modified 1997 data. Consequently, the consumption forecasts presented in the July draft document and utilized in the DEIR analysis remained unchanged in the final document published in August.

[4] Ken Goeke, CEC Specialist I, Demand Analysis Office, CEC, personal communication, October 20, 1998.

September 23, 1998

Ms. Maureen Gorsen
General Counsel
The Resources Agency
1416 Ninth Street
Sacramento, CA 95814
Attention: Nadell Gayou

Mr. Bruce Kaneshiro, Project Manager
Environmental Science Associates
225 Bush Street, Ste. 1700
San Francisco, CA 94104

Dear Ms. Gorsen and Mr. Kaneshiro:

Staff of the California State Lands Commission (CSLC or Commission) has reviewed the Draft Environmental Impact Report for Pacific Gas and Electric Company's Application for Authorization to Sell Certain Generating Plants and Related Assets Application No. 98-01-008, prepared for the California Public Utilities Commission. Based on this review, we offer the following comments.

Background

The State acquired sovereign ownership of all tidelands and submerged lands and beds of navigable waterways upon its admission to the United States in 1850. The State holds these lands for the benefit of all the people of the State for statewide Public Trust purposes which include waterborne commerce, navigation, fisheries, water-related recreation, habitat preservation, and open space. The landward boundaries of the State's sovereign interests are generally based upon the ordinary high water marks of these waterways as they last naturally existed. Thus, such boundaries may not be readily apparent from present day site inspections. The State's sovereign interests are under the jurisdiction of the Commission.

It also manages approximately 500,000 acres of school land owned in fee and approximately 700,000 acres of State-retained mineral interests in patented "school lands". The State's "school lands" are held in trust for the betterment of the common schools of the State and revenue, but statute, goes to the support of the State Teachers Retirement System.

Jurisdiction

[Begin BX1]

The Draft Environmental Impact Report for Pacific Gas and Electric Company's Application for Authorization to Sell Certain Generating Plants and Related Assets, Application No. 98-01-008, dated August 5, 1998, involves a number of facilities currently owned by PG&E

which are located on the State's sovereign lands and school lands and under lease with the California State Lands Commission. These leases are as follows:

PRC 415.1	Sovereign land; water intake and pipelines, San Joaquin River near Antioch, Contra Costa County
PRC 3124.1	Sovereign lands; barge dock near West Island, San Joaquin River near Antioch, Contra Costa County
PRC 4444.1	Sovereign lands; Pittsburg Power Plant, Sacramento River at Pittsburg, Contra Costa County
PRC 6794.2	School land; the operations and maintenance of existing access roads; Lake and Sonoma Counties
PRC 7083.2	School land near Trout Creek for a road right of way (Sections 27-34, T 18 N, R 11 W), Mendocino County

[End BX1]

[Begin BX2]

Pursuant to the lease terms of these leases, the leases cannot be assigned without the prior approval of the Commission. The following information is required by the Commission for review as part of any request for these assignments.

1. The name and complete business organization and operational structure of the proposed assignee, and the nature of the use of and interest in the lease premises proposed by the assignee. If the proposed assignee is a general or limited partnership, or a joint venture, we will require a copy of the partnership agreement or joint venture agreement, as applicable.

2. The terms and conditions of the proposed assignment, sublease, or encumbrancing or other transfer.

3. Audited financial statements of the two most recently completed fiscal years of the proposed assignee, and pro forma financial statements showing the projected income, expense and financial condition resulting from the use of the leased premises.

4. Any additional or supplemental information as the Commission may reasonably request concerning the proposed assignee.

Upon receipt and review of the above information, the Commission will evaluate the proposed assignee and grant approval or disapproval according to standards of commercial reasonableness considering the following factors within the context of the proposed use: the proposed assignee's financial strength and reliability, their business experience and expertise, their personal and business reputation, their managerial and operational skills, as well as other relevant factors.

[End BX2]

Enclosed is the Commission's standard application form that will need to be completed by the applicant and assignee. Please contact Diane Jones, Public Land Management Specialist, at 916-574-1843 concerning these assignments.

Sincerely,

MARY GRIGGS
Assistant Chief
Division of Environmental
Planning and Management

Note: Included with this comment were 17 pages of Form 54.2 (Rev. 1/12/96) documents. Since these cannot be reasonably duplicated here on this web page they are not available electronically. Should the viewer require a copy of these, please contact Webmaster for a printed copy.

BX. CALIFORNIA STATE LANDS COMMISSION

BX1 The commenter is partially correct. The cooling water intakes for the Contra Costa Power Plant extend approximately 250 feet into the San Joaquin River, which lies within the jurisdiction of the State Lands Commission (SLC). In addition, ten discharge pipelines extend into the river. Use of these facilities is subject to the terms of Lease No. PRC 415.1 with the SLC. The Contra Costa Power Plant also uses a marine terminal connected to the mainland, which is subject to Lease No. PRC 3124.1. PG&E's Contra Costa plant personnel are not familiar with the barge dock near West Island referenced in the comment, and do not use it for plant operations.[5] The Pittsburg Power Plant utilizes two offshore cooling water intakes and six offshore discharge outfalls that are subject to Lease No. PRC 4444.1 with the SLC. The referenced school land associated with Lease No. PRC 7083.2 is not included in the properties to be sold under the proposed project and would therefore not be subject to SLC action. Lease No. PRC 6794.2 is associated with the Geysers, but PG&E will retain the lease. The lease is for a non-exclusive easement for the operation and maintenance of existing roads used to access utility facilities in the Geysers area. The lease will be required by PG&E after the sale for continued access to its retained assets. Table 2.3 on page 2-44 notes that the Pittsburg plant is subject to a public lands lease with the SLC. The table is hereby modified to include the Contra Costa Power Plant:

Agency	**Permit Type/ Approval Required**	**Potrero**	**Contra Costa**	**Pittsburg**	**Geysers**
State Lands Commission	Marine Terminal/Public Lands Lease		X	X	

BX2 The information provided in the comment elaborates on the requirements of SLC approval of public lands leases that would be required for divestiture of the PG&E facilities. In response to Comment BX1, Table 2.3 of the DEIR has been modified to include the Contra Costa Power Plant as requiring SLC approval.

5 Sharon Maves, Environmental Coordinator, PG&E, personal communication, October 9, 1998.

September 1, 1998

Mr. Bruce Kaneshiro
CPUC EIR Project Manager
c/o Environmental Science Associates
225 Bush Street, Ste. 1700
San Francisco, CA 94104-4207

Dear Mr. Kaneshiro,

The Office of Ratepayer Advocates (ORA) presents its comments and questions regarding the Draft Environmental Impact Report (DEIR) for Pacific Gas and Electric Company's (PG&E) Application for authorization to sell certain generating plants and related assets. (Application 98-01-008). Essentially, ORA is concerned that the Hunters Point Agreement will result in significant environmental impacts at Potrero or in other parts of San Francisco that are not analyzed in the DEIR.

Comments & Questions Regarding PG&E's DEIR

[Begin C1]
Chapter 2, Project Description: Initially PG&E proposed to divest Hunters Point, but has since changed its position on that.[1]

PG&E now proposes *as part of this overall divestiture* to:

1. **reduce the amount of generation from Hunters Point to the minimum required by the ISO,**
2. retire Hunters Point as soon as the ISO will let PG&E,
3. promise not to use the Hunters Point site for a new generating plant and attach a restriction on the title of the Hunters Point site that would prevent a new owner from using the site for a power plant.

The above is relevant because items 1 and 2 will probably lead to an *increase* in the generation from Potrero resulting in *increased air emissions* at that power plant site. These are not analyzed in the DEIR. Item 3 is relevant because it affects the reliability of the electric system, and may create a need to increase generation (and associated emissions) at the Potrero site and/or a new transmission line corridor. All of these impacts are the direct cumulative impacts associated with PG&E's divestiture proposal. Under CEQA Guidelines section 15378, "project" is defined as "the whole of an action which has a potential for resulting in physical change in the environment..." Clearly, PG&E's actions re: the Hunters Point plant are part of the whole of the action and have a potential for resulting in physical change in the environment.
[End C1]

[1] Technically, the Commission has not yet approved PG&E's withdrawal of Hunters Point from its application.

[Begin C2]

Cumulative Scenario, page 3-3: The DEIR states "In light of the July 9, 1998 agreement between PG&E and the City...the cumulative analysis assumes that the Hunters Point Power Plant...is no longer operating by 2005. In order to successfully model the Analytical Maximum capacities of the plants to be sold, the cumulative analysis ***assumes*** that new generating 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." (emphasis added)

This statement assumes away precisely the impact that the EIR is supposed to measure. If PG&E's action to shut down Hunters Point permanently and prematurely as part of this Application triggers the need for the rapid construction of a large power plant in the northern part of the S.F. peninsula, that construction and operation is a **significant impact** of the agreement with CCSF, *not* part of the baseline.

[End C2]

[Begin C3]

1999 Baseline Scenario, section 3.6.1: This scenario is defined at pp. 3-9 to 3-11 in a confusing and unsupported manner. For example:

- Item 1 states that PG&E continues to own and operate Potrero, Pittsburg, Contra Costa and Geysers plants. It is not clear whether PG&E continues to own and operate Hunters Point since it is not mentioned.

[End C3]

[Begin C4]

- Table 3.1 is described as the projected 1999 annual capacity factors. Hunters Point is not listed on this table, yet under the baseline scenario and all the alternates it will be operating in 1999. This is an error and must be corrected.

[End C4]

[Begin C5]

- A new 480 MW plant is listed, but is shown as not operating in 1999. Isn't Hunters Point filling in this gap in generation? If not, what generation is?

[End C5]

[Begin C6]

- Foot "d" states that sometime between 1999 and 2005, Hunters Point would be retired and replaced with a new 480 MW plant.
    - When?

[End C6]

[Begin C7]

- What is the difference in forecast closure date of Hunters Point between the base case and any of the other cases?

[End C7]

[Begin C8]

- Does the DEIR make any analysis or assumptions about the *difference* in the closing dates of Hunters Point if the Commission approves the CCSF-PG&E agreement or if it doesn't?

[End C8]

Chapter 5, Cumulative Impacts

[Begin C9]

Future Plant Development, Section 5.2.2: The DEIR states that "In light of the [PG&E-CCSF] agreement, it appears reasonable foreseeable that, by 2005, generation and/or transmission facilities to serve the City of San Francisco will have been approved and constructed, and the Hunters Point Power Plant will no longer be operating." The DEIR argues this assumption is justified given the 4-5 year lead time for a new power plant (footnote 1, page 5-3)

- Does the DEIR make any assumption that the CCSF-PG&E agreement will affect how soon new generating capacity will be built that would allow PG&E to retire Hunters Point?
- Why wouldn't new generation be built at the same speed even without the CCSF-PG&E agreement?

[End C9]

[Begin C10]

The DEIR identifies (at p. 5-4) the "San Francisco Energy Facility" as the only project which has been publicly proposed which would provide even part of the local generation requirements that would result from the closure of Hunters Point. The project has been proposed for many years, but has never been able to get all the necessary permits.

- Is the EIR assuming that this project will be built by 2005?

[End C10]

[Begin C11]

- If not, does the EIR assume that future development is most likely or almost certain to occur at or near the Potrero plant site?

[End C11]

[Begin C12]

- What evidence is there to believe that there are other suitable sites available for a 480 MW generating plant, other than the Potrero or AES/San Francisco Energy Facility sites?

[End C12]

[Begin C13]

- The DEIR assumes that to replace the functions of Hunters Point, a new power plant will be needed within a small geographic area which will be connected to a PG&E substation, perhaps by underground cable, and will emit air pollutants. The DEIR should describe the likely impacts to urban and suburb neighborhoods from such development.

[End C13]

[Begin C14]

- The EIR talks generally about the need to locate the plant "somewhere on the San Francisco peninsula north of the Martin Substation in San Mateo county". (p. 5-4) Would a new substation and/or transmission lines need to be built?

[End C14]

[Begin C15]

- Are there constraints on which existing PG&E substations this new power plant could connect to in order to maintain or increase system reliability?

[End C15]

[Begin C16]

- Could a new generating plant adjacent to Potrero connect to the existing substation, or would it need to connect to the Hunters Point Substation? What other existing substations could it connect to?

[End C16]

[Begin C17]

- The DEIR identifies the new power plant as a cumulative impact, but does not state how it is related to the current application. The DEIR should state how it is related to the current application. The DEIR should state that the intent of PG&E's agreement with the City is to (1) deny the use of the Hunters Point site for such a plant and (2) accelerate the construction of such a plant.

[End C17]

[Begin C18]

- The DEIR states "Such facility improvements will likely occur only following extensive system planning studies and with coordination among generating plant owners (including the new owner of the Potrero Power Plant), the City of San Francisco, PG&E...and the ISO." (p. 5-4)
  - What is the evidence supporting this statement?
  - Where is there any indication in the record that there is a requirement for "coordination among generating plant owners"?
  - What agency or firm has committed to performing these "system planning studies"?
  - Will the results of such studies be public?
  - Who will be bound by the findings of such studies?
  - Regarding new generating plants, is it correct that the ISO lacks the authority to order an energy generating firm to construct new plants?

[End C18]

[Begin C19]

- Where in the DEIR is their any identification and description of any incremental effect(s) on the environment caused by the CCSF-PG&E agreement?

[End C19]

[Begin C20]

Referring to Table 5.2 on p. 5-18 footnote "c", the DEIR states that this scenario assumes that PG&E will operate its Hunters Point plant at minimum capacity per the agreement with CCSF. Yet Hunters Point is not shown at all on Table 5.2. This is an error. Projected capacity factors for Hunters Point should be included in Table 5.2.

[End C20]

[Begin C21]

Chapter 6, Alternatives Evaluated: The alternative proposed by PG&E in its Amendment regarding immediate change in the operation of the Hunters Point plant, and its early retirement must be considered if it is likely to change the environmental impacts relative to the no project alternative. The DEIR should add and analyze the proposed changed operations at Hunters Point as Alternative #4.

[End C21]

Sincerely yours,

/s/

Truman L. Burns

ORA Project Coordinator
415/703-2932

C. OFFICE OF RATEPAYER ADVOCATES

C1 The project reviewed by the DEIR is the proposed divestiture of PG&E power plants. PG&E amended its divestiture application in June 1998, removing the Hunters Point Power Plant from the project. PG&E's application to modify its divestiture application was approved by the CPUC on October 8, 1998. The CCSF-PG&E agreement is not part of the project, and the future retirement of the Hunters Point plant pursuant to the agreement is a separate action from the proposed project. However, the analysis of divested plant operations takes the agreement into account. The 1999 analytical maximum scenario assumes, pursuant to the agreement, that PG&E would operate its Hunters Point plant at the minimum level necessary to ensure continued electric reliability (see footnote "c" in Table 5.2 on page 5-17 of the DEIR). The DEIR also assumes for the 2005 cumulative analysis that the Hunters Point plant would be closed by that year (see footnote "d" in Table 5.2 on page 5-17 of the DEIR). Thus, the impact of the agreement on future operations of the plants proposed to be sold has been taken into account. Because there are various ways that the electrical service from the Hunters Point plant might be replaced, the DEIR considers the analytical maximum results of two cumulative variants considering different combinations of future power plants in San Francisco and transmission system upgrades. These cumulative scenarios are described in detail in the DEIR on pages 5-16 through 5-20.

C2 As noted above, PG&E applied to modify its divestiture application, withdrawing the Hunters Point plant from the proposed sale, as a consequence of the June 9, 1998, agreement. Therefore, as noted on page 2-5 of the DEIR, the project analyzed by the DEIR does not include the divestiture of the Hunters Point Power Plant. PG&E's planned future action to shut down Hunters Point is not and never has been a part of its application. With respect to commenter's concerns about the potential environmental impacts of the construction of a new power plant to replace the Hunters Point plant, Chapter 5 of the DEIR analyzes at a general level the potential cumulative impacts of a new power plant, together with the proposed divestiture. Such a new plant is treated as a cumulative project, not as part of the baseline.

C3 The 1999 Baseline scenario defined in Section 3.6.1 of the DEIR describes conditions relevant to the proposed project as they would occur in 1999 without implementation of the project. The 1999 Baseline assumes the continued operation of Hunters Point Power Plant. This is mentioned under Item 3. To clarify, Item 1 on page 3-9 of the DEIR is revised to read:

1. PG&E continues to own and operate Potrero, <u>Hunters Point,</u> Pittsburg, Contra Costa and Geysers plants, obtaining revenue through reliability contracts with the ISO and by selling power from the facilities through the Power Exchange (PX).

C4 The Hunters Point plant was included in the modeling for 1999, but was not included in this table because it is not proposed to be sold. While this may have caused some confusion, DEIR preparers were concerned that including the Hunters Point plant in the tables could also cause confusion. Capacity factors for Hunters Point are included in the DEIR Tables of Attachment G (e.g., see Table G-1, 1999 Baseline). Also please see response to Comment C3.

C5 See responses to Comments C3 and C4. The Hunters Point plant is assumed to be operating in the 1999 Baseline (see Table G-1) and also in the 1999 Analytical Maximum (see Table G-4, which shows the Potrero plant at its Analytical Maximum). Given the agreement between PG&E and San Francisco, Hunters Point is not assumed to operate at its Analytical Maximum (as shown in a sensitivity modeling run reported in Table G-5), but is assumed to operate at a minimum level to support system reliability (see Table G-18).

C6 In order to conservatively portray potential 2005 cumulative impacts, the Hunters Point plant is assumed to be retired and replaced with a new power plant as of 2005. Footnote 1 on page 5-3 of the DEIR discusses in more detail the timing of the closure of Hunters Point Power Plant. The information discusses the steps that would need to be taken and makes it clear that the exact year of closure of the Hunters Point plant is not known.

C7 There was no "forecast" closure date assumed in the DEIR for the Hunters Point plant for any of the operating scenarios. However, it was assumed for all of the cumulative future scenarios that the plant would be closed by 2005. This is based on a July 9, 1998 agreement between PG&E and the City and County of San Francisco in which PG&E agreed to permanently shut down the Hunters Point plant as soon as the facility is no longer needed to sustain electric reliability in San Francisco and the surrounding area. The agreement provides that the City and PG&E will advocate the expeditious development of generation and/or transmission facilities to replace the Hunters Point plant. Therefore, all of the variants examined in the cumulative analysis presented in the DEIR assume that Hunters Point is no longer operating by 2005 (see Table 5.2). As of 2005, the Hunters Point plant is assumed to be replaced, even in the No Project Alternative (see DEIR Table G-2). The Hunters Point plant is assumed to be still operating in 1999, however, which constitutes the Baseline scenario against which project impacts were assessed.

C8 No difference was assumed for closing dates. See page 1-4 of the DEIR (including Footnote 1) concerning the DEIR's assumptions with respect to the agreement. See response to Comments C6 and C7 with regard to the timing that was assumed in the DEIR and see response to Comment C1 regarding the CPUC decision affirming the agreement reached between PG&E and the City and County of San Francisco regarding the removal of the Hunters Point plant from the project.

C9 The DEIR did not speculate on the future of Hunters Point plant if the agreement were not in place. However, the agreement appears to provide impetus for the permitting and construction of new generation facilities since it ensures that the Hunters Point plant will be closed once it is no longer required for reliability purposes. However, as also noted, it is possible that the Hunters Point plant will not close precisely by 2005; the cumulative impacts analysis of the DEIR does not depend on the projects assumed within it having occurred by any particular year. The EIR assumes that, in light of the agreement, new generation and/or transmission capacity to replace the Hunters Point plant will be in place by 2005. As stated in Footnote 1 on page 5-3 of the DEIR, permitting and construction of a new generation or transmission facilities normally take approximately 2-3 years and 2 years, respectively.

As a means of providing further clarification to the scope of this EIR, the following paragraph is hereby added after the end of the first full paragraph on page 4.5-56 of the DEIR and after the second paragraph on page 5-4 of the DEIR:

> <u>This EIR has been limited to an examination of the project proposed by PG&E namely, the sale of three fossil-fueled power plants and PG&E's geothermal facilities. It has looked at potential environmental impacts of the sale of these plants and the change in the BAAQMD's Regulation 9, Rule 11 necessary to allow such a sale. This EIR has considered, as part of its analysis of potential cumulative impacts, the addition of generation in San Francisco. However, nothing in the EIR is or purports to be a review of the potential environmental impacts of development or repowering of any of the sites PG&E is selling in a level of detail sufficient for siting, permitting, or project approval of such future development or repowering. This EIR is not intended to substitute for any analysis of the air quality issues that may need to be considered by the BAAQMD when it prepares its next clean air plan.</u>

C10 The DEIR does not assume that the San Francisco Energy Facility (SFEF) will be built by 2005. The modeling performed for 2005 does assume that the Hunters Point plant will be closed by 2005 because a new replacement facility in San Francisco will be on line by that time. The DEIR considers two alternative cumulative scenarios for replacing the Hunters Point plant: (1) construction of a new 480 MW plant and (2) construction of a new 240 MW plant (which could be the proposed 240 MW SFEF plant, or could be a separate, newly proposed 240 MW plant), together with a new transmission line to serve San Francisco (see DEIR page 5-5, first paragraph). All new power plant equipment is assumed to be typical of current proposed construction featuring, for example, General Electric's Frame 7G design turbines.

C11 No specific assumption is made as to where such a new facility would be located, except that it would be "north of the Martin Substation in San Mateo County, including anywhere within the City and County of San Francisco" (DEIR page 5-4). The DEIR also recognized on page 5-4 that new generating facilities "could be located on the same site as, or adjacent to, the Potrero Power Plant and could thus be considered an expansion of that plant." The analysis of cumulative environmental impacts specifically considered the effects of collocating a new plant with the Potrero plant (see DEIR pages 5-22 through 5-39).

C12 It is understood that the SFEF proponents did consider other sites before settling on the two that were put forward by the proponents during the CEC siting proceeding for that facility, and that other bidders in the CPUC Biennial Resource Planning Update of the early 1990s may have also considered other sites. It is not known if either of the SFEF proposed sites were considered suitable for a 480 MW facility, double the size of the proposed SFEF. Any new power plant site is subject to the CEC permitting process, as well as project-specific environmental review under CEQA.

C13 As discussed above in responses C10 and C11, the DEIR analyzes such cumulative impacts throughout Section 5.3 (beginning on page 5-16 of the DEIR). The impacts are discussed in Section 5.3.2 for the 2005 Cumulative Analytical Maximum (assuming a new 480 MW plant in San Francisco) and in Section 5.3.3 for Cumulative Variant 1 (assuming transmission line upgrades and a new 240 MW plant in San Francisco).

C14 To incorporate a new plant, a switchyard would be needed for “step-up transformers” that increase the voltage of the generator output to a level compatible with the PG&E transmission system. Furthermore, transmission lines from the new plant’s switchyard would need to connect with PG&E’s transmission or distribution system in San Francisco. The switchyard at either the Potrero plant or the Hunters Point plant would provide an electrically ideal place to connect the new plant to the transmission and distribution grid. However, the CCSF-PG&E Agreement makes the use of the Hunters Point plant switchyard unlikely. Very likely, a new transmission line connecting the new plant to existing lines would be required, as was proposed for connection with the proposed SFEF facility. The connection would likely be at an existing substation; however, depending upon the location of the new plant, it may be more economical to construct a new substation to accommodate the new plant and any associated transmission line constructed for that plant.

C15 There are no known firm constraints limiting the choice of substations with which a new facility might connect. However, concerns about common mode failures or localized disruptive events suggest that it would be preferable for the new plant not to share a common feed with the Potrero Power Plant. This would ensure that a single transmission line failure would not disable both the Potrero plant and the new plant.

C16 Except for considerations described in the response to Comment C15, a new generator could connect at the Potrero substation, especially if PG&E completes the planned underground cable extension between the Potter and Hunters Point substations. The DEIR only analyzed construction of a new plant at a general program level, and the CPUC did not conduct studies to determine the feasibility of constructing a new plant and related transmission facilities in San Francisco. Therefore, the DEIR did not consider what other substations could be used for connecting a new plant to the grid. Presumably, the new plant could connect to any point in PG&E’s transmission or distribution system north of the Martin Substation, provided that the new owner could obtain right-of-way and permits for constructing the new facilities.

C17 The agreement between PG&E and the City does specify that its purpose is to accelerate the permanent closure of the Hunters Point plant, and it precludes building a new generation facility at the Hunters Point site. Implementation of the agreement, however, is not related to the current application and is expected to occur with or without the proposed divestiture. These points of the agreement are identified on page 1-4 of the DEIR, within Section 1.2.3.

C18 The agreement between the City and County of San Francisco and PG&E to close the Hunters Point Power Plant states that "The City and PG&E will advocate the expeditious development of capacity (generation and/or transmission) to replace the Hunters Point Power Plant in order to ensure continues electric reliability in San Francisco in a manner [that] minimizes adverse community and environmental impacts." The precise studies that will be prepared and the planning process that will be used in the decision-making process for replacing the Hunters Point Power Plant is unknown at this time, and are not within purview of the CPUC. However, it stands to reason, and the shared jurisdictions of the various agencies suggest, that significant coordination will be needed prior to constructing any facility improvements. If an Application for Certification with the CEC is required (which is highly likely, given that the CEC reviews all new construction or repowering resulting in an increase in generating capacity of 50 MW or more), then that coordination will largely take place among government agencies through the CEC's siting process. Additionally, the Western Regional Transmission Association would be involved in the planning of any transmission facilities, if only to determine whether other parties should share in the cost of construction of the new facilities. Both of these planning processes are open to the public. PG&E may conduct its own planning process for replacing Hunters Point generation, which would not necessarily be open to the public, but any new construction would require permits from government agencies, and the permitting processes for such permits would be open to the public. The CPUC is not aware of any particular existing commitments by agencies or firms to perform system planning studies.

It is correct that the ISO lacks the authority to order construction of a new facility. The ISO does, however, have the authority to preclude the premature closure of the Hunters Point plant (before it is replaced and system reliability ensured) as long as it remains as a designated must-run facility.

C19 As noted in response to Comment C2, the project subject to review by the DEIR does not include the divestiture, the closure or the replacement of the Hunters Point Power Plant. In light of the CCSF-PG&E agreement, however, the DEIR assumes that the Hunters Point plant will be operated in 1999 at a minimum level to ensure system reliability (see footnote "c" in Table 4.5-26 on page 4.5-57). Also in light of the agreement, the DEIR 2005 cumulative impacts analysis assumes that the Hunters Point plant will be replaced and will be retired when it is no longer needed to support reliability requirements for San Francisco. The DEIR thus analyzes the effect of the CCSF-PG&E agreement by considering the environmental impacts of various future scenarios that could occur when the Hunters Point Power Plant is closed (see response to Comment C1).

C20 See responses to Comments C3, C4, and C5.

C21 As noted in response to Comments C7 and C19, it has been assumed throughout the DEIR that the Hunters Point Power Plant will be retired when the facility is no longer needed to sustain electric reliability in San Francisco and the surrounding area and the Federal Energy Regulatory Commission (FERC) has authorized PG&E to terminate PG&E's Reliability Must Run Agreement (RMRA) for the facility. The agreement between PG&E and the City and County of San Francisco governing the retirement of Hunters Point was signed by PG&E and the Mayor of San Francisco, and approved by the San Francisco Board of Supervisors and the San Francisco Public Utilities Commission. On October 8, 1998, the CPUC approved the agreement (Decision No. 98-10-029). The projected retirement of the Hunters Point plant will occur regardless of whether or how the proposed project is implemented; it is a separate action unrelated to the proposed project.

Sept. 10, 1998

BRUCE KANESHIRO, PROJECT MANAGER
c/o Environmental Science Assoc.
225 Bush St., Suite 1700
San Francisco, CA 94104

re; PG&E Application for Divestiture Draft EIR
Public Comment PLANTS 13 and 16 LAKE COUNTY

Dear Mr. Kaneshiro:

[Begin D1]
Please be advised that our community was greatly impacted by the planning and construction of plants 13 and 16 in the county of Lake, and that this community was very active in this process and the siting of these plants. We would encourage you to assure us that the safety and security of our community is maintained at all times.
[End D1]

Yours truly,

Meriel Medrano, Manager
ANDERSON, SPRINGS COMMUNITY SERVICE DISTRICT

REGIONAL AND LOCAL AGENCIES

D. ANDERSON SPRINGS COMMUNITY SERVICE DISTRICT

D1 This EIR was undertaken to ensure that environmental impacts resulting from the transfer of ownership of four PG&E power plants (including the commenter's specific concern of Units 13 and 16 at the Geysers) are identified and any significant impacts mitigated where feasible. The EIR addresses environmental aspects of community safety and security as related to the proposed sale of the Geysers units, including Units 13 and 16. Note that the DEIR concludes that, with implementation of the mitigation measures proposed in the DEIR, there will be no local significant impacts.

September 21, 1998

Bruce Kaneshiro,
CPUC EIR Project Manager
California Public Utilities Commission
c/o Environmental Science Associates
225 Bush Street, Suite 1700
San Francisco, CA 94104-4207

RE: Comments on CPUC Draft EIR on PG&E Divestiture Project, Application #98-01-008

Dear Mr. Kaneshiro,

Thank you for the opportunity to comment on the California Public Utility Commission (CPUC) draft environmental impact report (EIR) analyzing the potential environmental impacts of the divestiture of three of the four Bay Area fossil-fuel power plants currently owned by PG&E. As you know, the Bay Area Air Quality Management District continues to follow closely the CPUC's implementation of the restructuring of the electric utility industry, as mandated by state law, AB 1890. District staff has participated in meetings on divestiture with CPUC staff, and more recently at the CPUC community meeting and public hearing held on August 24, 1998 and September 15, 1998, respectively.

[Begin E1]
The draft EIR is an ambitious effort to forecast future potential significant environmental impacts of the sale of these Bay Area electric utility boiler power plants. The District wishes to comment on and clarify some of the points raised in the report. First, the draft EIR analyzes, as one of its cases, the scenario of uncontrolled NOx emissions from these plants as a result of deregulation. The argument is that the new owner of one or more of these power plants would be exempt under industry restructuring because the plant(s) would no longer be "a CPUC regulated utility." While the CPUC is absolutely correct in including these scenario to help ensure that their review is as complete as possible under the California Environmental Quality Act (CEQA), the EIR should clarify that this is an unlikely scenario. The District is committed to modifying its Regulation 9, Rule 11 so that the rule will continue to apply to these power plants, regardless to ownership. Interested parties will get public notices this fall to discuss the proposed necessary rule changes. The intent is to achieve NOx reductions at least equivalent to the current rule, with the same emission limits and deadlines as the current system wide schedule. The prohibition on oil burning, which will minimize fine particulate PM10/PM2.5 and toxic emissions, will of course also be retained in the rule.
[End E1]

[Begin E2]
The draft EIR uses the concept of an analytical maximum to forecast future emissions, using plausible maximum future power plant generating rates with increased power demand and a 25 percent below market cost natural gas fuel supply. The report should emphasize that this concept is a reasonable worst case upper bound and not a likely case.

[End E2]

[Begin E3]
The draft EIR predicts a possible exceedance of the federal 1-hour NOx standard near the Pittsburg power plant in 1999 (Table 4.5-32). The report should modify this prediction by noting that the background NO_2 level used already includes much of the power plant's emission contribution, and hence there is some double counting. We suggest that more refined modeling would show that this predicted excess is an artifact. In any event, the phenomenon is at worst only temporary, as the Regulation 9, Rule 11 standards becomes more stringent in subsequent years.
[End E3]

[Begin E4]
The draft forecasts that future emissions of toxic air contaminants from each of the power plants to be sold, even under the analytical maximum scenario, will remain well under the significance thresholds of risk assessment. Nevertheless, members of the public have asked how far the area of maximum impact is from each plant. A clarifying discussion around Table 4.5-34 would be helpful.
[End E4]

[Begin E5]
The draft EIR estimates that future emissions of reactive organic gases, nitrogen oxides, and particulate matter from the power plants in 2000 and 2003 under the analytical maximum scenario may be higher than the forecasts in the District's *1997 Clean Air Plan* (Tables 4.5-35, 36, and 37). However, it should be explained that plan forecasts intentionally do not use a worst case scenario for each industry sector; otherwise the cumulative total of these sectors would result in a grossly overestimated basin inventory. Furthermore, the *1997 Plan* did not incorporate aspects of electricity utility industry restructuring not then known. The District will review the plant forecasts as part of its preparation for the *2000 Clean Air Plan*.
[End E5]

[Begin E6]
The draft EIR notes that increasing the generating capacity or repowering of any of the existing units at the power plants, up to 49 megawatts, would be exempt from California Energy Commission (CEC) approval (page 3-4). Please note that even a nominal increase in capacity of a generating unit would subject it to District new source review with its attendant more stringent Best Available Control Technology (BACT) and emission offset requirements.
[End E6]

[Begin E7]
Finally, the draft EIR reports on the recent agreement between PG&E and the City and County of San Francisco, for the utility company not to sell the Hunters Point power plant. With the late removal of the Hunters Point plant from the divestiture application to the CPUC, and technically from the project under CEQA, much of the completed environmental assessment information on Hunters Point was apparently not included in the draft EIR. However, because there is no date certain for the shutdown of the Hunters Point plant and because continued operation or curtailment of the plant will impact operation of at least the Potrero power plant, the CPUC

should consider a fuller discussion of the various Hunters Point operational scenarios and impacts, perhaps including some of the detailed analyses in a report appendix.
[End E7]

Thank you for the opportunity to provide these comments. We look forward to continue working with the CPUC and other interested parties throughout the CEQA process on the proposed PG&E divestiture project. If you wish to discuss any of the foregoing comments, please call Kenneth Lim, Principal Air Quality Engineer, at (415) 749-4710.

Very truly yours,

Ellen Garvey
Executive Officer/Air Pollution Control Officer

cc: Peter Venturini, ARB
David, Maul, CEC
Christie McManus, PG&E

EG:KL:kl

E. BAY AREA AIR QUALITY MANAGEMENT DISTRICT

E1 The DEIR examined NO_x emissions under two different regulatory scenarios (i.e., with modifications to BAAQMD Regulation 9, Rule 11 and without such modifications) to ensure CEQA analysis of all possible project implementation scenarios. It is acknowledged in the DEIR (e.g., on page 4.5-53) that the BAAQMD intends to modify Regulation 9, Rule 11 to ensure its continued applicability to all of the electric utility steam boilers at the four Bay Area power plants, regardless of whether they are utility-owned. The NO_x emissions scenario that does not include such modification can therefore be considered a worst-case scenario.

E2 The DEIR does note on page 4.5-55 that the analytical maximum scenario is "extremely unlikely" to be a true operating scenario. It was used to provide a conservative analysis or, as noted in the comment, a reasonable worst-case upper bound case.

E3 The table referred to by the commenter (Table 4.5-32 on page 4.5-68 of the DEIR) projects an exceedance of the state 1-hour nitrogen dioxide standard in 1999, not of the federal 1-hour NO_X standard. A more refined analysis has been carried out since the release of the DEIR. The new analysis indicates that the 1-hour nitrogen dioxide standard will not be exceeded. See Response to comment B11 for details on the analysis.

E4 Based on the modeling results, the maximum offsite impacts for all three plants are relatively near the facilities, ranging from 0.5 to 1.5 miles away. At other locations that are beyond this zone, the estimated concentrations are much lower, principally because of dilution of pollutants in the atmosphere. Sensitive receptors, such as schools in ther regions around the plants, were included in the modeling analysis, and the impacts at these sensitive receptors were found to be less than significant.

E5 The commenter is correct in noting that different approaches are used in developing emissions forecasts for a basin-wide plan compared to a project-specific CEQA analysis because they serve different purposes. While a reasonable worst-case approach is appropriate for the latter, it may lead to illogical policies if used for the former. It is acknowledged that one of the reasons that the power plant emissions forecasts included in the *'97 Clean Air Plan* differ from those presented in the DEIR is that much of the information concerning the effects of electric utility restructuring and power plant divestiture had not been developed yet to allow for incorporation of that information by the BAAQMD into the *'97 Clean Air Plan*. The fact that BAAQMD will review regional emissions forecasts, including power plant emissions, and amend the regional air quality strategy, if necessary, lends support to the conclusion that the project's potential inconsistency with the regional air quality plan would be a temporary effect.

E6 The commenter is correct that even nominal increases in capacity would require new source review by the BAAQMD. As noted in the second to the last sentence of the second bulleted item on page 3-4 of the DEIR, any expansion or repowering of generating units (even under 49 MW) "would require issuance of new permits and accompanying environmental review."

E7 Please refer to responses to Comments C4 and C5.

September 21, 1998

President Richard A. Bilas
CA Public Utilities Commission
505 Van Ness Avenue
San Francisco, CA 94102-3298

Dear Sir:

We are grateful for the opportunity to comment on the Draft Environmental Impact Report (EIR) regarding the proposed divestiture of the Potrero Power Plant, and to articulate again the City and PG&E's mutual objectives. These objectives include ensuring that the Potrero Plant is operated in an environmentally appropriate way, that the Hunters Point Plant is shut down as soon as possible, and that regulators and power procedures are responsive to community concerns.

[Begin F1]
The City's main concerns regarding the divestiture, as analyzed in the Draft EIR, are the potential for human health effects due to increased particulate emissions and the regional implications of increased emissions of ozone precursors. San Franciscans should not have to endure the magnitude of increased emissions dismissed in this report as inconsequential. The public health of our citizens, and the attractiveness of the Bay Area as a place to do business, are inexorably tied to the quality of air we breathe and our attainment of environmental policy goals.

I encourage the State to consider these potential consequences in more depth, and to impose necessary mitigation measures. Appropriate measures may include (1) limiting Potrero Plant operations; and/or (2) obtaining air emission credits by achieving emission reductions in the local area.
[End F1]

Sincerely,

/s/

Kofi S. Bonner
Chief Economic Policy Advisor

cc. Gordon R. Smith, President & CEO
Pacific Gas & Electric Company

September 21, 1998

Mr. Bruce Kaneshiro
CPUC EIR Project Manager
c/o Environmental Science Associates
225 Bush Street, Suite 1700
San Francisco, CA 94104-4207

RE: Comments on the Draft EIR on PG&E's Electric Generation Asset Divestiture, A.988-01-008

Thank you for the opportunity to review the above referenced document. This letter and attachments provide the City and County of San Francisco's comments regarding the Draft Environmental Impact Report (DEIR). As you will see, our greatest concern is the increase in air emissions that will result from the project and potential adverse health impacts. We believe that the final EIR should address this issue in more depth, particularly with regard to local impacts and feasible mitigation measures. Our comments also address other areas including the use of the Analytical Maximum, land use, water resources, and hazards.

General/Summary Comments:

[Begin F2]
- The final EIR should identify, for any new power plants or transmission capacity that is assumed, the specific year in which these additions or replacements are assumed to be fully operational.

[End F2]

[Begin F3]
- In the final EIR please ensure that there is a clear correlation between the tables in the Executive Summary (Tables S.1, S.3, S.4, S.5, S.6, and Part of S.6) and the tables in Appendix G. For example, in Table S-1, the column headings should indicate the tables in Appendix G relied upon. Similar annotations to Appendix G should be provided for the remaining tables in the Executive Summary.

[End F3]

[Begin F4]
- The Draft EIR correctly points out the massive changes that are occurring in the utility industry here in California. In order to not underestimate the potential impact of these changed conditions, the environmental impacts of divestiture in the final EIR should start from an analysis of each divested plant's impact, based upon the plant's **physical** maximum output. This physical maximum output would be the maximum electricity each plant could produce, taking into account down times due to forced outages, maintenance periods, and any permit restrictions. Additional comments on this item are contained in Exhibit A, attached.

[End F4]

[Begin F5]

- *Page S-11, Section S.6 (Cumulative Impacts)*: For Alternatives 2A and 2B, what are the underlying assumptions and data for the Year 2005?

[End F5]

[Begin F6]

- *Page S-16*: The DEIR concludes that "the environmentally superior alternative to the project is a combination of Alternative 2A, the bundling of Potrero, Contra Costa and Pittsburg and Alternative 3, the sale of the Geysers plant to the steam field operators . . . The magnitude of the impacts would be less than with the project, but the levels of significance of the impacts would be identical to the project." This paragraph should be expanded to indicate: 1) what specific environmental impacts are decreased with Alternatives 2A and 2B and what is the level of decrease and 2) what is meant by the phrase "the levels of significance of the impacts would be identical"?

[End F6]

[Begin F7]

- *Page S-21, Table S.6; Also P. S-31, Table S-2*: Impact 4.5.5 is designated as significant for the proposed project and for Alternative 2A and 2B. For the proposed project the footnote states that the impact is "unavoidable". What is meant by unavoidable? As explained below in the discussion on air quality, this impact can be mitigated. The reference to "unavoidable" should be deleted and Impact 4.5.5 identified as "S/M" -- "a potentially significant impact; impact would be reduced a less than significant by mitigation measures required in this report." The final EIR should then add a discussion of available mitigation measures (plant output limits, emission offsets).

[End F7]

[Begin F8]

As discussed above re page S-16, greater explanation is needed for the designation of "L" and "G" for Alternative 2.

[End F8]

<u>Land Use and Planning</u>

[Begin F9]

- *Figure 4.1-1 (page 4.1-3) and Figure 4.1-4 (page 4.1-8)* should be amended to delete the pipeline to the Pier 70 Marine terminal and the terminal from the Potrero Plant site. Those properties are owned by the Port of San Francisco and will not be transferred with the sale. PG&E must seek an assignment of their lease to the purchase of the Potrero Plant.

[End F9]

<u>Water Resources</u>

[Begin F10]

- *Section 4.4.2 (Local Setting)* should discuss the environmental impact issues identified in the significance criteria presented in Section 4.4.3 (flood hazards, storm water runoff, public water supplies, water quality, and groundwater resources), especially the contribution of each plant to surface and groundwater quality and condition. Discussing these issues will provide support for the impact conclusions described in Section 4.4.4.

[End F10]

[Begin F11]
- For the Potrero Plant, the final EIR should include a figure illustrating monitoring wells and outfalls (in this or the Hazards section), and include any water quality data from those wells, if the information is necessary to support the impact analysis. This could be as brief as a list of chemicals of concern present in the water, with the data and figures provided in an appendix.[End F11] [Begin F12]The final EIR should also include a summary of chemicals discharged and a discussion of any NPDES compliance issues.[End F12]

[Begin F13]
- *Impact 4.4-2 (page 4.4-15)* introduces a new significance criteria -- violation of state or federal effluent limitations. This criteria should be included in Section 4.4.3.

[End F13]

[Begin F14]
- Section 4.4.4 should be expanded to address the proposed project's anticipated effect on each of the impact topics identified by the significance criteria in Section 4.4.3. Impacts should be discussed separately for each of the plants.

[End F14]

[Begin F15]
- Some of the existing NPDES permits will expire during the period covered by the impacts analysis. The final EIR should clarify whether the analysis assumes that the RWQCB will renew the permits without modification and the basis for this assumption.

[End F15]

[Begin F16]
- *Page 4.4-6 (Potrero Plant)*: this section should cross-reference Part 4.4.9 (Hazards), and vice-versa, since there are major environmental contamination issues associated with the groundwater setting.

[End F16]

<u>Air Quality</u>

[Begin F17]
- It was difficult to determine which version of the must-run contract for Hunters Point is assumed in the DEIR. The final EIR should assume version C, given PG&E's Agreement with CCSF.[End F17] [Begin F18]The final EIR should also clearly state how by PG&E/City Agreement regarding the shutdown of Hunter's Point affects the assumptions and conclusions in this chapter. If the CPUC has not approved the PG&E Amendment regarding the Agreement by the time of the issuance of the final EIR, then the EIR should discuss how the scope of the project and impacts might change.[End F18]

[Begin F19]
- The final EIR should clarify what air quality retrofits are assumed and in what year. For any retrofits assumed to have occurred in 1998, the final EIR should check that such retrofits have actually been accomplished.

[End F19]

[Begin F20]
- The figures attached as Exhibit B represent CCSF's understanding of the emissions data assumed in the DEIR. Are these emissions calculations correct? Similar charts should be included in the final EIR.

[End F20]

[Begin F21]
- What measures are proposed to ensure that the actual emissions do not exceed those stated in the DEIR? The City suggests that regular monitoring and dissemination of monitoring results.

[End F21]

[Begin F22]
- As indicated on p. 4.5-18, the BAAQMD Regulation 9, Rule 11 establishes NOx emission rate limits for power plants within its jurisdiction. It is our understanding that any new operator of these power plants will be required to operate in compliance with these NOx emission rates, even if the new owner only purchases one plant. In year 2005, the NOx emission rate limit under the "bubble" option is 0.018 pounds per million BTU. However, several scenarios referenced in Appendix G indicate that this limit is not satisfied. Specifically, in Tables G-2 and G-8, the average NOx emissions for the Pittsburg facility are 0.020 lb/mmBTu; and in Tables G-6, and G-17, the average NOx emissions for the Pittsburg facility are 0.023 lb/mmBUT.

[End F22]

[Begin F23]
- *Part 4.5.4 (Significance Criteria), page 4.5-50, second full paragraph*: Given the projected increase in 1999 Potrero Plant emissions relative to the no-project baseline (for example, a 56.8% increase in NOx), did the CPUC consider whether the local area's air quality-related health burdens constitute a "special circumstance" for significance considerations? If not, why not?

[End F23]

[Begin F24]
- *Part 4.5.4 (Significance Criteria), page 4.5-50, Criteria #1*: The significance criteria do not appear to account for the Bay Area's non-attainment status for ozone and particulate matter (listed in Table 4.5-2, "Air Basin Attainment/Non-Attainment Designations")> For example, "Prevention of Significant Deterioration" (PSD) is a standard typically used for attainment areas; "New Source Review" (NSR) is typically used in non-attainment area. Are PSD standards used for all criteria pollutants? If so, what is the rationale? (For example, one difference is that significance under an NSR standard can be triggered by 100 additional tons/year of NOx; the Potrero Plant would emit 610 additional tons/year at the Analytical Maximum). Generally, it seems that the analysis should reflect the area's non-attainment status because more stringent analyses may be appropriate for non-attainment pollutants.[End F24] [Begin F25]Also, were the numerical criteria for PM-10 significance derived from BAAQMD Regulations or other sources?[End F25]

[Begin F26]
- *Table 4.5-26*: Please explain the difference between the Hunters Point emissions levels in this table and in Table G-1 (334 v. 210 tons NOx/year). Which levels were used to determine significance?

[End F26]

[Begin F27]
- *Page 4.5-32*: Even assuming that fossil-fueled plants would emit mainly particles PM2.5 or smaller, the DEIR analysis may be incomplete, since it does not appear to have accounted for the secondary formation of PM2.5 from NOx and ROG emissions.

[End F27]

[Begin F28]

- *Page 4.5-62*: The DEIR appears to analyze only the primary impacts of NOx and PM. The DEIR does not evaluate the secondary pollutant formation of ozone and particulate matter (for example, by using a photochemical model such as CAMx™ or UAMV). What is the rationale for not conducting such an evaluation?

[End F28]

[Begin F29]

- *Page 4.5-75, first full paragraph*: The last sentence of the paragraph states: "Based on the converse to that concept, the contribution of divestiture to overall cumulative ambient risk would be less than significant because the project-specific impact would be less than significant." This approach contradicts the purpose of a cumulative impacts analysis. CEQA calls for agencies to identify situations where impacts in themselves are not significant, but could contribute to a significant effect in combination with the impacts of other projects.

[End F29]

[Begin F30]

- *Mitigation Measure 4.5-5 (page 4.5-81)*: The DEIR concludes that even if Regulation 9, Rule 11 or its equivalent were applied to the divested plants, the 1997 Clean Air Plan would not be met if the plants were operated at the Analytical Maximum, and that this is a significant, unavoidable, temporary (until Year 2003) impact. No mitigation is proposed. As shown in the charts attached as Exhibit B, the increase in emissions will be substantial, especially on a cumulative basis. The impact of these increased emissions can be mitigated by at least the following means: (1) restricting operating hours and/or (2) obtaining air emissions offsets. The final EIR should include these or other mitigation measures to ensure less than significant levels of emissions.[End F30] [Begin F31]In addition, emissions after 2003 will still increase substantially with the project, as opposed to no project. Absent enforceable mitigation, what assurance is there that the emissions will not in fact be higher than projected after 2003, and thus trigger a significant impact?[End F31]

[Begin F32]

- *Page 4.5-70 (Cumulative (2015) Bay Area Analysis*: In order to produce a valid cumulative impacts analysis, the mobile and project sources for all criteria pollutants should be added together and the effects evaluated (as was done for carbon monoxide).

[End F32]

Hazards

[Begin F33]

- The analysis of hazards related to contamination of soil and groundwater at the Potrero Plant site is inadequate, and is not based on detailed information available at the time of publication of the DEIR. The Potrero Plant site is known to have substantial soil and groundwater contamination issues, as the Phase II report published in June 1998 ("Phase II Environmental Site Assessment: Pacific Gas and Electric Company, Potrero Power Pant, "by Fluor Daniel GTI) acknowledges.

[End F33]

[Begin F34]

- *Section 4.9.1 (Regional Setting), page 4.9-1 et seq*: This section discusses the regulatory framework for hazardous materials and site remediation (although omitting reference to Proposition 65 and local ordinances), but not any specific setting information. Please

include a summary of environmental conditions at and surrounding each plant. The final EIR should identify whether there any underground storage tanks present on the Potrero property and should also indicate that polyaromatic hydrocarbons were found at the former manufactured gas plant facility at Potrero.
[End F34]

[Begin F35]
- *Page 4.9-4 (Hazardous Materials And Waste)*: Please discuss asbestos, PCB's lead-based paint and electromagnetic fields at the Potrero Plant in order to support the significance conclusions.

[End F35]

[Begin F36]
- *Page 4.9-5 (Potential Site Contamination)*: Please reference the Phase II report published in June 1998 ("Phase II environmental Site Assessment: Pacific Gas and Electric Company, Potrero Plant,' by Fluor Daniel GTI).[End F36] [Begin F37]Is there a schedule for remediation of the Potrero Plant site? If so, this should be included in the final EIR.[End F37] [Begin F38]Did the PEA done by PG&E determine if the site poses any current hazards to human health or the environment? If so, this should be discussed in the final EIR.[End F38]

[Begin F39]
- *Page 4.9-6, second full paragraph*: What is the current status of the "material recognized environmental conditions?"

[End F39]

[Begin F40]
- *Page 4.9-6, second full paragraph and page 4.9-15, third full paragraph*: Is PG&E doing the Phase II assessment and risk assessment voluntarily, or has it been directed to do these by a regulatory agency? If so, which regulatory agency is it? Who will determine what cleanup is required, and when it is performed?

[End F40]

[Begin F41]
- *Impact 4.9-1 (page 4.9-14)*: What factors related to divestiture would accelerate remediation efforts at the Potrero Plant?[End F41] [Begin F42]What are the regulatory requirements that would require remediation by either the purchaser or PG&E?[End F42]

[Begin F43]
- The DEIR does not address how divestiture could affect the potential remedies proposed in the Phase II report for the Potrero Plant. For example, the Highest Ranking Alternative for Remedial Issue 1 -- Soil and Groundwater in the Central Site Area would require a plant shutdown of up to 30 days (see page 84 of the Phase II report). The final EIR should address the Phase II report and how such a shutdown relates to the "must-run" and economic assumptions of the analysis. The report estimates a total of over $33 million in required remediation, so it is not a minor issue. If remediation is not accomplished prior to shutdown of the Hunters Point Plant, would a less-protective remedial alternative eventually have to be implemented because of the Potrero Plant's role in maintaining the San Francisco Operating Criteria reliability?

[End F43]

[Begin F44]

- *Mitigation Measure 4.9-1 (page 4.9-17)*: The DEIR assumes early cleanup. The City is concerned, however, that divestiture could result in less timely and less effective remediation because of changes in site control, loss of access to records, introduction of new potentially responsible parties, and the lesser ability of a purchaser in a deregulated environment to absorb substantial increases in remediation costs.

[End F44]

[Begin F45]

Pages 4.9-16 and 17 summarize PG&E's intentions regarding retention of legal responsibility for cleanup and describe a process of regulatory oversight that it intends to follow. However, Mitigation Measure 4.9-1 only calls for PG&E to submit each plant's Risk Assessment to the CPUC and to the purchaser. In addition, the fourth full paragraph on page 3-5 states that "issues associated with the liability for environmental cleanup are expected to be resolved contractually between each new owner and PG&E."

An expression of intent by PG&E is inadequate, by itself, to assure that the sites will be cleaned up by PG&E once ownership is transferred. The City is concerned that PG&E's proposed responsibility for cleanup could be transferred, diluted, or avoided as a result of the divestiture unless PG&E enters into binding remediation commitments prior to sale.

Mitigation Measure 4.9-1 should indicate requirements that PG&E include each purchase and sale agreement provisions that implement the assumptions made in the DEIR regarding PG&E's post-transfer responsibilities, and that PG&E will enter into an enforceable remedaition agreement with one or more appropriate regulatory agencies prior to transfer of title.

[End F45]

[Begin F46]

- *Impact 4.9-3 (page 4.9-19); page 4.9-4*: In the final EIR, the paragraphs summarizing the properties of chemicals typically found at the power plants to be divested would be useful in the setting section. For the Potrero Plant, similar information should be provided for sodium hypochlorite, sodium bisulfite, and the solvents, degreasers and petroleum-based oils that, according to the last paragraph on page 4.9-4, are hazardous materials used at the plant.[End F46] [Begin F47]Lead-based paint is generally considered a hazardous material where building renovation or demolition is possible, and so should be discussed as applicable.[End F47]

[Begin F48]

- *Mitigation Measure 4.9-3 (page 4.9-21)*: Even though PG&E personnel will continue to operate the divested plants after title is transferred, three business days seems too short a time for the new owner to review detailed documents and procedures for which it will be legally responsible as soon as title is transferred. The health and safety documents should be made available to the prospective purchasers sooner.

[End F48]

[Begin F49]

- *Impact 4.9-5 (page 4.9-23)*: Site remediation often generates larger quantities of hazardous waste than typified by operations, although there is no information provided in the DEIR for these particular sites. The final EIR should clarify how the impact of remediation waste generation is included in Impact 4.9-1.

[End F49]

[Begin F50]
- *Impact 4.9-6 (page 4.9-24)*: The DEIR does not provide information on whether EMF emissions at any plant would increase as a result of the project's assumed higher operations levels. If there would be increases, then at a minimum the purchaser should be required to mitigate the emissions in accordance with CPUC policy.

[End F50]

<u>Local Cumulative Impacts</u>

[Begin F51]
- Table 5.1 (page 5-12) and Section 4.5 (Air Quality) should rely on a current list of local projects near the Potrero Plant. Please contact the San Francisco Planning Department and the Port of San Francisco for updates to this list.

[End F51]

[Begin F52]
- The EIR analysis does not appear to fully address the cumulative impacts of the proposed project in combination with local projects. Several of the local projects listed (and several that should be added to the list) are localized generators of PM10 emissions. The surrounding community has concerns regarding the cumulative effect of these generators when viewed in combination with the Potrero Plant. Please expand the cumulative impacts assessment to address this issue.

[End F52]

Please do not hesitate to call me at (415) 558-6384 if you have questions regarding these comments, or if I can be of further assistance.

Sincerely,

/s/

Hillary E. Gitelman
Environmental Review Officer

cc: Kofi Bonner
Laurie Park
Elaine Warren
Dian M. Grueneich

Exhibit A
Use of the "Analytical Maximum" and
Need to Analyze Impacts Under the Physical Maximum

[Begin F53]
The DEIR (p. S-6) indicates that the new owners of the fossil-fueled plants would tend to operate at higher levels than PG&E's continued ownership because of the following three factors: the portfolio effect; fuel procurement practices; and the ability of new owners immediately to participate in the direct access market. The DEIR also states (page S-8): "The ability of new owners to participate immediately 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 PG&E."

The DEIR then proceeds to define an analytical maximum that somehow is supported to take into account all three of the above factors. The DEIR state: "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 of which plants operations would increase at a particular plant." (p. S-8) The report then defines a gas price level at which somehow all of the three above factors are considered, even though gas price level is really only directly related to the second factor.

Much of the remainder of the DEIR is based upon sophisticated system modeling, which produces operating levels that result from this arbitrary gas price assumption. However, many other assumptions also need to be made about the operation of the interconnected system, all of which can have an impact upon operating levels of the divested plants. Based upon all of these subjective factors, it is a stretch at best to conclude that the resulting "Analytical Maximum" and modeling results have any correlation to what can reasonably expected to be a limit to future changes in operations of the plants under divestiture.
[End F53]

[Begin F54]
In comparison, calculation of the operating level based upon the physical maximum, which the City proposes be included in the final EIR, is an easy exercise. At a minimum, the environmental effects of plant operation at the physical maximum levels (as defined above), should be displayed in the final EIR, in addition to those impacts calculated in the DEIR. The likelihood of reaching the physical maximum level of operation could be also addressed in the final EIR, so that decision makers can fully evaluate the possible impacts of divestiture.
[End F54]

The following questions and comments supporting our belief that environmental impacts should at least be investigated at the physical maximum operating level:

[Begin F55]
1. On page S-7, the DEIR states that a major assumption is that: "Both the PX and ISO continue to commit and dispatch the plants based upon 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 report requirements." Very little with respect to the PX and the ISO stays constant these

days. The Federal Energy Regulatory Commission (FERC) is holding detailed settlement discussions with respect to the must run agreements, for all the plants that sell to the ISO, including those being divested. In addition, the ISO, in corporation with the transmission owners, are developing transmission planning criteria for the ISO system as a whole. In this process, they are trying to reconcile differences between the historical practices of each of the Transmission Owners and also interpret and apply WSCC and NERC criteria at a local level which is a change from past practice.[End F55] [Being F-56]Finally, PG&E has concurrently proposed major additions to their transmission system in the Bay Area which are not accounted for in the DEIR analysis.[End F56]

[Begin F57]

2. other "key assumptions" in the DEIR involve powerplants being added in San Diego and Nevada. Tremendous uncertainty exists as to where and when new generation will be added in the western region. The final EIR should explain what new powerplants are being assumed, the basis for that assumption, and some indication of how the impact analysis would change if either more or fewer new powerplants are developed than is assumed in the final EIR.

[End F57]

[Begin F58]

3. Section 3.4 of Attachment C describes "Factors that Could Produce Change." These factors bolster our position that the final EIR needs to look at physical maximums for the plants being divested. The DEIR says that such factors are "too speculative to consider at this time" but it is not at all clear that these factors are more unlikely than many of the assumptions that are included in the Analytical Maximum cases.

[End F58]

[Begin F59]

4. As pointed out in the DEIR, p. C-2: "The first basic premise is that restructuring as directed through legislation and Commission decisions will lead to substantial, fundamental changes in how California's electric utility system operates.

[End F59]

[Begin F60]

5. As pointed out in the DEIR, p. C-3, "if an operator can reduce costs by changing operating mode or reducing cost of fuel by even a small amount, sales from that unit can rise substantially." The DEIR includes on single assumption – the 25% decrease in an owner's gas cost – which is evidently meant to capture all of the effects of changes in operating mode and fuel costs. As explained above, use of a physical maximum in the final EIR will capture the impact of such changes without requiring numerous additional operation studies.

[End F60]

[Begin F61]

6. Section 3.1 and Section 3.2 point out a litany of factors that all lead to a conclusion that no one can predict with any certainty how operation of the divested plants might change. No attempt is made to indicate how the EIR reader knows that the Analytical Maximum captures these uncertainties. Use of the physical maximum in the final EIR will account for these uncertainties.

[End F61]

Note: Included with this comment were two pages of Exhibit B. Since these cannot be reasonably duplicated here on this web page they are not available electronically. Should the viewer require a copy of these, please contact Webmaster for a printed copy.

September 17, 1998

Hillary Gitelman
Office of Environmental Review
Department of City Planning
1660 Mission Street
San Francisco, CA 94103

Dear Ms. Gitelman:

The San Francisco Department of Public Health has reviewed the Draft Environmental Impact Report (EIR) for the Pacific Gas and Electric Company's Application for Authorization to Sell Certain Generating Plants and Related Assets Application No. 98-01-008. We are specifically concerned with the sale of the Potrero Plant in San Francisco. We would like to provide you with the following written comments on the EIR:

Comment 1. General Comment

[Begin F62]
Overall, we found the assessment of health impacts due to the anticipated changes in local air quality was limited. The report based its significance criteria mainly on existing administrative rules that set permissible exposure increments and limits. This approach ignores the breadth of human health effects that have been associated with specific air pollutants, and it ignores the concept of a linear dose-effect response relationship between these adverse health outcomes and incremental increases in pollution.[End F62] [Begin F63]A more complete risk assessment process of this project should reflect the avalable scientific evidence and should address the following:

A. Separate risk characterizations should be made for each criteria air pollutant. This is most important for "non-attainment" pollutants, ozone and particulates, but also relevant for nitrogen oxides for which emissions increases are the greatest.

[End F63]

[Begin F64]
B. Risk assessment should be done on a regional as well as local level.

[End F64]

[Begin F65]
C. Exposed populations should be identified and located, and sensitive subpopulations should be estimated.

[End F65]

[Begin F66]
D. The most sensitive health outcome for each pollutant should be as determined from consideration of all of the outcomes studies in the epidemiologic literature (i.e., cardio-respiratory mortality, hospital admissions and emergency room visits, exacerbation of chronic respiratory disease, etc.).

[End F66]

[Begin F67]

E. The population health burden for incremental exposure changes should be estimated utilizing the slope of the exposure-response relationship, the population at risk and background outcome frequency.

[End F67]

We believe the approach outlined above is feasible and would provide a less ambiguous estimate of the population health impact of the proposed project.

[Begin F68]

Comment 2. Page 4.5-6 Last paragraph

A. The paragraph summarizing the health effects of PM10 and PM2.5 should distinguish between health impacts due to chronic and acute exposure to PM10.

B. The paragraph should reference studies on the impact of acute exposure to PM10, specifically, daily rates of respiratory and cardiovascular mortality, hospital admissions and emergency room visits as well as probability of asthma exacerbation. Since the US EPA criteria document referred to in the Draft EIR (page 4.5-84) reviewed ALL studies relating to both acute and chronic exposure to PM, it would be appropriate to use this criteria document and the associated staff report in addition to selected studies.

[End F68]

[Begin F69]

Comment 3. Page 4.5-12 1st full paragraph, Introduction to Risk Assessment

The last sentence states, “Information on risk assessment methodology is presented in the discussion of the Potrero Power Plant setting.” The page number with this information should be referenced. Also cross reference what is in Appendix G and what is in the main document in terms of risk assessment methods.

[End F69]

[Begin F70]

Comment 4. Page 4.5-25 1st full paragraph

What residences are downwind from the power plant (as related to the wind rose on page 4.5-27)? The location and approximate population size of these areas should be stated.

[End F70]

[Begin F71]

Comment 5. Page 4.5-31 2nd full paragraph, Sentence 1

The sentence obscures effects due to chronic and acute exposures, doesn’t refer to cardiovascular impacts, and downplays the relationship of daily concentrations of PM to mortality (“in some cases”). While there are still controversies in the observed PM-mortality relationships, they have been replicated in more than 50 studies, and they are at least as strong in terms of data quality as those for other outcomes.

[End F71]

[Begin F72]
Comment 6. Page 4.5-31 2nd full paragraph, Sentence 2

The sentence reads, "Most of these studies have shown relationships between PM exposure and respiratory effects during air pollution episodes in major metropolitan areas, where daily ambient air concentrations exceeded 300 μg/m^3." The above statement is incorrect as relationships between PM and health effects have been shown at concentrations much lower than 300 μg/m^3; furthermore, the sentence in paragraph 2 of the following page, "Typical annual average concentrations of PM-10 at these cities ranged from 18-58 μg/m^3...." directly contradicts the above statement. In addition, the word, "cardiopulmonary," in the above statement should replace the word, "respiratory."
[End F72]

[Begin F73]
Comment 7. Page 4.5-31 3rd full paragraph

Sentence 1 should read, "A draft report released by...reported that 1992 hospitalization rates for ... were higher in Bayview Hunters Point than any other part of San Francisco. Sentence 2 should use the past tense. Sentence 3 should begin, "To better understand the causes of the increased hospitalization rates."
[End F73]

[Begin F74]
Comment 8. Page 4.5-32 2nd full paragraph

The first sentence states, "With regard to fine particles (PM2.5), several studies cited in the EPA report indicate that significant increased hospitalization and respiratory symptoms occur when PM-2.5 24-hour concentrations increase by 20-25 μg/m3 (Schwartz et al., 1994; 1996; Thurston et al., 1992, 1994)." There seems to be some confusion in how these studies were interpreted. These studies and others are describing *linear* relationships. When relative risks are presented, they use a realistic interval such as the interqartile range of concentrations in the study area or 10 or 20 μg/m3 increases which could be observed from one day to the next. **These effects would be just as *statistically* significant with 1 μg/m3 increases.**
[End F74]

[Begin F75]
Comment 9. Page 4.5-50 Significance Criteria #1

The source of the numerical criteria presented (5 μg/m3 increase 24 hour average PM10 and 1 μg/m3 annual average increase) is not referenced.
[End F75]

[Begin F76]
Comment 10 Page 4.5-50 Significance Criteria #4

In sentence three and four, a numerical interval, 24 hour 20 μg/m3 PM2.5 & annual 10 μg/m3 PM2.5, is established as the significance criteria. In sentence one, the significance criteria is the production of "increased respiratory ailments." These criteria are inconsistent because where a

linear dose-effect relationship exists, any increase in exposure would be expected to result in a quantifiable increase in the burden of disease. (See comments 8 & 9.) Also, the references for the above numerical targets are not cited. It is possible that the study from which the above numerical limits have been derived may have used the term “significance” to connote significance or the term may reflect the authors own judgment. (see general comment above.) Finally, does the criteria consider only incremental increases only being considered or is the cumulative effect of air pollution being considered? How are expected number of days exceeding 20 μg/m3 determined? Why are these incremental increases for PM2.5 greater than the ones given for PM10 in Criteria #1 when PM2.5 is a subset of PM10?
[End F76]

[Begin F77]
Comment 11 Page 4.5-50 Significance Criteria #5

How does the recent Federal non-attainment designation of the Bay Area Region for ozone affect the determination of significant exposure and health impacts? Will any increases in ozone precursors, both ROG’s and Nox, be consistent with the region’s plans to come under future compliance?
[End F77]

[Begin F78]
Comment 12 Page 4.5-63 Table 4.5-29

There is an apparent error in the PM2.5 row. The power plant contributes 1.2 μg/m3 PM2.5 to ambient concentrations, but the ambient concentration after this contribution is listed as 1.2 μg/m3. There is a similar error in the next 2 columns.
[End F78]

Thank you for considering our comments. Please call Dr. Rajiv Bhatia at 252-3931 if you have any questions on our comments.

Sincerely,

/s/

MITCHELL H. KATZ, MD
Director of Health

cc: Rajiv Bhatia, Occupational and Environmental Health, D.P.H.

October 7, 1998

Mr. Bruce Kaneshiro
CPUC EIR Project Manager
c/o Environmental Science Associates
225 Bush Street, Suite 1700
San Francisco, CA 94104-4207

RE: Comments on the Draft EIR on PG&E's Electric Generation Asset Divestiture (A.98-01-008)

Dear Mr. Kaneshiro:

[Begin F79]
The City and County of San Francisco submitted comments on September 21, 1998 on the Draft EIR regarding PG&E's ongoing divestiture project. We wish to offer the following supplement to those comments, with regard to the last sentence in my cover letter to President Bilas and the City's comment on Mitigation Measure 4.5-5 (DEIR, p. 4.5-81).

The purpose of the above-referenced comments from the City was to encourage the Commission to include, in the final EIR, a discussion of mitigation measures, to the extent such measures are available or appropriate. The City defers, of course, to the Commission's responsibility under CEQA to determine whether any mitigation measures are necessary or appropriate.
[End F79]

We thank you for the opportunity to provide this supplement to our prior comments.

Sincerely,

/s/

Kofi S. Bonner
Chief Economic Policy Advisor

cc: President Richard A. Bilas,
California Public Utilities Commission
Gordon R. Smith, President & CEO,
Pacific Gas and Electric Company

F. CITY AND COUNTY OF SAN FRANCISCO

F1 The EIR has conducted extensive analyses with regard to air quality and there is little evidence to suggest that this project, which includes the sale of the Potrero Power Plant in San Francisco, will result in significant health impacts, or other air quality impacts, from PM-10 or ozone precursors. The most important direct effect of the project is that changes will be required to BAAQMD Regulation 9, Rule 11. This is because Regulation 9, Rule 11 is currently written to apply to utility electric power generating steam boilers, and the new owner would not be a utility. Regulation 9, Rule 11 also must be modified because it applies a system-wide average to the NO_x emission concentration levels, and with the sale of the plants, there will be multiple owners of the Bay Area electric power generating steam boilers. This is assured because the Hunters Point Power Plant is no longer included in the auction and will continue to be owned by PG&E until it can be shut down. The EIR includes Mitigation Measure 4.5-5 that requires modifications to Regulation 9, Rule 11, or permit revisions, so that the end result would be that substantially equivalent emission rate limits as currently apply to PG&E would apply to any new owner.

BAAQMD Regulation 9, Rule 11 is critical to the substantial reductions that will be required of the electric generating steam boilers. As can be seen in the emission limits on page 4.5-18 of the DEIR, NO_x emission rates will drop about 90 percent between 1997 and 2005. The other key feature of Regulation 9, Rule 11 is the prohibition on oil burning, which will minimize fine particulate PM-10 and toxic emissions. BAAQMD is in agreement that Regulation 9, Rule 11 should apply to the new owner(s) of these power plants. The following is a quote from the BAAQMD comment letter (first page, second paragraph) on the DEIR:

> The District is committed to modifying its Regulation 9, Rule 11 so that the rule will continue to apply to these power plants, regardless of ownership. Interested parties will get public notices this fall to discuss the proposed necessary rule changes. The intent is to achieve NO_x reductions at least equivalent to the current rule, with the same emission limits and deadlines as the current system wide schedule. The prohibition on oil burning, which will minimize fine particulate PM10/PM2.5 and toxic emissions, will of course also be retained in the rule.

Although the EIR identifies a potential for increased operation of the Potrero Power Plant, the electric generating steam boiler (Unit 3) will continue to use natural gas exclusively as a fuel (as required by Regulation 9, Rule 11 since 1995), which is the cleanest burning of the fossil fuels (see DEIR page 4.5-1), and the predominant winds blow the emissions out over the bay. Please see also responses to Comments 4-2 and F70.

Please see response to Comment F30 regarding the suggested mitigation measures for limiting Potrero plant operations and/or obtaining air emission credits.

Finally, with respect to the commenter's main concern about potential health effects related to particulate emissions (i.e., PM-10), some studies have indicated that any incremental increases in PM-10, such as during particular 24-hour periods when the ambient air already exceeds PM-10 standards, can cause health impacts. An in-depth study of those potential effects is not believed to be necessary or appropriate for review in this EIR, but may be necessary or appropriate in connection with reviews of environmental and community impacts of any development or expansion plans for these or other power plant sites. In addition, the purchase and sale agreement for these plants requires the owner to consult in good faith with the City and County of San Francisco about the impacts of any planned expansion or development of the Potrero Power Plant site.

Detailed responses to the commenter's concerns regarding potential health effect issues are provided in responses to Comments F62, F63, F66, F67, F68, F73, and F74.

F2 Table S-3 (page S-13 in the DEIR) shows that the EIR assumes that the Pittsburg District Energy Facility (PDEF) will be on line by 2005 (as analyzed in Cumulative Variant 2) and that another new power plant in San Francisco will also be on line by 2005, either a new 480 MW power plant (analyzed in the primary cumulative impacts analysis) or a new 240 MW power plant in San Francisco, together with a new transmission line (under 2005 Cumulative Variant 1). It was considered too speculative to determine more precisely the year in which these plants would first be on line. The timing of plant retirements that are assumed to occur under various scenarios can be determined from data presented in Table 5.2 (see pages 5-17 and 5-18 of the DEIR).

As indicated in Chapter 5 (page 5-3) of the DEIR, it appears reasonably foreseeable, in light of the June 9, 1998 agreement between PG&E and the City and County of San Francisco, that generation and/or transmission facilities to serve the City of San Francisco and replace the Hunters Point Power Plant would be in place by 2005. Footnote 1 (page 5-3) explains that, since permitting for new generation or transmission facilities normally takes about two to three years and construction of new facilities requires approximately two years, it is reasonable to forecast that such activities would be complete by 2005. However, as footnote 1 also explains, it is possible that the Hunters Point Power Plant will not have closed precisely by 2005, in which case it is presumed that PG&E would continue to operate the Hunters Point plant at the minimum level necessary for reliability purposes, until the conditions necessary for closure of the plant were satisfied. As noted, the cumulative impacts analysis of the DEIR does not depend on the projects assumed within it having occurred by any particular year. If the Hunters Point plant were to be replaced by 2007 rather than 2005, for instance, the analysis would remain valid and applicable.

F3 The commenter suggests that tables (G-1 to G-20) in Attachment G should include notes as to where in the DEIR the data are used. This would be a very time consuming and complex process since these tables are used as background or supporting data in varying ways and in many places throughout the DEIR. However, for the sake of clarity, the following changes are hereby added:

To Table S.1 (and Table 3.1) the title is changed as follows:

PROJECTED POWER PLANT ANNUAL CAPACITY FACTORS[a,g]

And the following footnote is added:

[g] Capacity factors shown on this table are taken from Tables G-1, G-5, G-3, G-4, and G-6 and correspond to the fifth, sixth, seventh, eight, and tenth columns of data from left to right on the table.

To Table S.3 (and Table 5.2) the title is changed as follows:

PROJECTED CUMULATIVE ANALYSIS POWER PLANT ANNUAL CAPACITY FACTORS[a,i]

And the following footnote is added:

[i] Capacity factors shown on this table are taken from Tables G-1, G-3, G-4, G-5, G-6, G-9, and G-14 and correspond to the fifth, sixth, seventh, eight, and ninth columns of data from left to right on the table.

To Table S.5 (and Table 6.1) the title is changed as follows:

PROJECTED ALTERNATIVES ANALYSIS POWER PLANT CAPACITY FACTORS[a,f]

And the following footnote is added:

[f] Capacity factors shown on this table are taken from Tables G-1, G-3, G-4, G-5, G-6, G-2, G7, and G-8 and correspond to the fifth, sixth, seventh, eight, ninth, and tenth columns of data from left to right on the table.

Information in Tables S.4 and S.6 is not directly correlated to the tables found in Attachment G. Therefore, Tables S.4 and S.6 remain unchanged.

F4 Please refer to the responses to Comments F53 and F61.

F5 Except for the unique differences being analyzed in Alternatives 2A and 2B (as explained on pages 6-16 and 6-17 of the DEIR), the underlying assumptions and data for the Year 2005 (Alternatives 2A and 2B) are the same as for the 2005 Cumulative Scenario, as described on pages 3-3 and 3-13 of the DEIR and also in Attachment G, pages G-7 to G-9.

F6 The environmental impacts associated with Alternative 2B (no bundling of plants for sale) would generally be increased over those of the project, and not decreased as indicated by the commenter. The environmental impacts of Alternative 2A (bundling the fossil-fueled plants for sale) would be decreased compared with the impacts of the project to the extent that the magnitude of the project's impacts are based on the potential for plant operation levels to rise under divestiture. This is because the tendency of new owners to generate more electricity than PG&E would be somewhat reduced under Alternative 2A compared to the project as proposed. (Please see page 6-16, third paragraph, of the DEIR for a more detailed explanation of this.) As an example, because it is assumed that power generation under Alternative 2A would be less than under the proposed project, there would be less change in the use of water resources by the plants and discharges into receiving water bodies would be less, resulting in reduced impacts to water quality and temperature and to aquatic biological resources. Similarly, decreased operations under Alternative 2A could result in reduced noise levels in the vicinity of the plants compared to the project. The precise amounts by which the impacts of Alternative 2A may be lessened in comparison to the project is not quantifiable. The analytical maximum capacities of the plants are the same under both the project and Alternative 2A; the implementation of Alternative 2A would merely lessen the likelihood that the plants would operate at such capacities. All of the impacts of Alternative 2 are discussed in Section 6.4 of the DEIR, pages 6-9 through 6-28. The discussion on page S-16 referenced in the comment is intended as a brief summary of Section 6.4. For additional details on impacts of the alternatives, the reader is referred to that section.

Regarding the phrase "the levels of significance of the impacts would be identical," this means that while the magnitude of impacts under Alternative 2A would be reduced, the significance level identified for each project impact would be the same under the alternative. In other words, while the impacts to water quality, for example, would be less under Alternative 2A than under the proposed project, the impact would be less than significant for both the alternative and the project. Table S.6 of the DEIR illustrates this relationship between the project and each alternative for all impacts identified in the environmental analysis.

F7 Please see response to Comment F30.

F8 As discussed in the response to Comment F6, Table S.6 of the DEIR illustrates the comparative magnitude of impacts between the proposed project and the project alternatives. The "L" indicates that the magnitude of the impact under the alternative would be less than under the project. Conversely, a "G" indicates that the impact would be greater under the alternative. Table S.6 is intended only as a summary/overview of the impacts of the project and alternatives. Substantial details on the impacts are provided in Chapter 4 for the project and in Chapter 6 for the alternatives.

F9 In order to reflect the City's comment and for clarification, Figure 4.1-1 (page 4.1-3) and Figure 4.1-4 (page 4.1-8) are hereby amended as follows: The property boundary around the site will no longer include the pipeline to the Pier 70 Marine terminal and the terminal from the Potrero plant site. Please see the revised Figures 4.1-1 and 4.1-4 below. The

INSERT FIGURE 4.1-1

Click on the box to display Figure 4.1-1

POTRERO POWER PLANT SURROUNDING LAND USES

INSERT FIGURE 4.1-4

Click on the box to display Figure 4.1-4

POTRERO POWER PLANT SURROUNDING ZONING

commenter is correct that the lease (which is included in the sale) must be transferred by PG&E to the new owner, subject to approval by the Port of San Francisco.

F10 The significance criteria listed in Section 4.4.3 are all of the water resources related criteria from CEQA Appendix G. The water resources changes associated with the project are from the potential operation of the plants at higher levels and from construction of minor facilities such as access roads and fences. The nature of the project is such that there would be no impacts to flooding and stormwater runoff quantity (effects on stormwater quality from construction is discussed). The environmental setting and effects on public water supplies are discussed in Section 4.12, Utilities and Service Systems. The setting for water quality, most importantly the NPDES permit limits and groundwater, are described in Section 4.4.2.

F11 There are no project-related impacts on groundwater at the Potrero plant. Changes in cooling water use would not affect groundwater, since the water is taken from, and discharged to, Lower San Francisco Bay. Construction of the minor facilities or the remediation of soils may require groundwater dewatering. Any water quality concerns from these activities would be addressed in complying with the required permit conditions.

F12 The DEIR contains descriptions of the discharge sources and the types of chemicals discharged from these sources in Section 4.4.2. A summary of the NPDES permits is provided in Section 4.4.1; the new owners would be required to comply with the existing permit conditions.

F13 The significance criteria listed on page 4.4-13 of the DEIR are hereby amended as follows:

- cause substantial flooding, erosion, or siltation;
- expose people or structures to flood hazards;
- generate substantial storm water runoff;
- contaminate a public water supply;
- substantially degrade water quality; ~~or~~
- substantially degrade or deplete groundwater resources; <u>or</u>
- <u>violate any state or federal effluent limits.</u>

F14 CEQA requires an EIR to focus on the significant or potentially significant effects of a project. The project would not result in substantial flooding, contamination of a public water supply, or any of the other occurrences identified as significance criteria in Section 4.4.3. It is therefore not required and it is unwarranted in the interest of conciseness (also mandated by CEQA) to include a series of impact statements declaring that no impact on flooding, water supply, etc. would occur with implementation of the project. Similarly, it is also unnecessary to provide separate impact statements and discussions for each of the power plants when the impacts identified and the discussions supporting them apply to each of the plants.

F15 Impact 4.4-2 on page 4.4-15 is hereby amended to add the following after the fourth paragraph:

> NPDES permits are issued by the Regional Boards for 5-year periods. The permittee is required to apply for renewal of the permit and provide considerable data to the Regional Board on historical discharges and water quality monitoring. The Regional Board may renew the permit with the existing permit conditions and discharge limitations or may issue more stringent limitations, depending on the water quality conditions of the receiving body and the performance of the discharger. Since there is no reason to predict otherwise at this time, this analysis assumes that the NPDES permits for the plants will be renewed with the same effluent limitations as currently exist.
>
> According to 40 CFR 122.61, the NPDES permits would be transferred from PG&E to the new owner with the same permit conditions.

F16 Given the way the DEIR is organized, the information related to groundwater contamination at the Potrero Power Plant is all in Section 4.9, Hazards, so the appropriate cross reference would be to that section. The following sentence is added to the DEIR at the end of the first paragraph on page 4.4-1.

> The reader is also referred to Section 4.9, which contains a discussion of groundwater contaminants at the power plants.

F17 The DEIR assumes that the Hunters Point Power Plant would be operating only to meet reliability. The commenter is correct that such operational regime is consistent with Version C of the Must Run Agreement.

F18 On October 8, 1998, the CPUC issued Decision 98-10-029, which approved the agreement between PG&E and the City and County of San Francisco regarding the Hunters Point Power Plant. This agreement is summarized within the second complete paragraph on page 1-4 of the DEIR. The DEIR analysis is consistent with the terms of the agreement. Please see response to Comment F20 regarding DEIR assumptions with respect to future Hunters Point plant operations.

F19 On page G-6 of Attachment G, the following statement is made:

> All postulated emission control improvements listed in Appendix B, Table B-2 of PG&E's Fossil Plant PEA were incorporated into modeling, as well as the retirement of Pittsburg 3 and 4; however, Pittsburg 1 and 2, were assumed retained for voltage support, with SCR added to Pittsburg 2 to permit observance of the Bay Area air quality bubble standards in 2005.

During visits to each of the power plants during the winter and spring of 1998, the EIR preparers confirmed that the Proposed Retrofit Technology shown in Table B-2 of PG&E's

TABLE B-2
HYPOTHETICAL NO_x RETROFIT CONTROL SCHEDULE UNDER A FOUR BAY AREA PLANT NO_x BUBBLE

Unit	Proposed Retrofit Technology	Timing	Projected NO_x Emissions (ppm)[a]
Contra Costa 6	Combustion Modifications	1998	90
	Low NO_x Burners (30% FGR[b])	2000	24
	In-duct Selective Catalytic Reduction[c]	2003	10
Contra Costa 7	Low NO_x Burners (30% FGR[b])	1997	24
	In-duct Selective Catalytic Reduction[c]	2003	10
Pittsburg 1-4	Combustion Modifications	1998	125
	Restrict Load Range	1999	125
	Cold Standby or Retire	2002	125
Pittsburg 5	Combustion Modifications	1997	75
	Low NO_x Burners	2001	30
	In-duct Selective Catalytic Reduction[c] (30% FGR[b])	2003	10
Pittsburg 6	Combustion Modifications	1996	75
	Low NO_x Burners	2001	30
	In-duct Selective Catalytic Reduction[c] (30% FGR[b])	2004	10
Pittsburg 7	Combustion Modifications	1997	50
	Conventional Selective Catalytic Reduction	2003	10
Potrero 3	Boiler Tuning	1996	150
	Combustion Modifications	1997	115
	Over-fire Air/FGR	1999	75
	Low NO_x Burners	2001	42
	Conventional SCR	2003	10
Hunters Point 2	Combustion Modifications	1998	125
	Cold Standby/Retire or Retrofit Controls	2002	
Hunters Point 3	Combustion Modifications	1998	125
	Cold Standby/Retire or Retrofit Controls	2002	
Hunters Point 4	Combustion Modifications	1996/7	105
	Over-fire Air/FGR/Low NO_x Burners	1999	30
	In-duct Selective Catalytic Reduction	2003	15

[a] 1.0 ppm equals about 0.00121 lb/MMBtu at 3 percent excess oxygen.
[b] FGR = Flue Gas Recirculation.
[c] Selective Catalytic Reduction (SCR) technology requires the storage and use of aqueous ammonia at the plant sites. Facilities and practices would be designed to avoid spills and contain them in the unlikely event they occurred. Ammonia emissions are limited to 10 ppm (hourly) under BAAQMD Rule 9-11 paragraph 311. Current SCR technology also uses a vanadium pentoxide catalyst, which, if possible, would be returned to the manufacturer for metals recovery. If the catalyst cannot be returned, it would be disposed of as a hazardous waste.

Fossil Plant PEA was already installed or would be installed during 1998, and would be operable on each specified unit no later than January 1999.

F20 With one exception, the charts prepared by the commenter are fair depictions of the emissions data presented in the DEIR. The one exception is for the A-Max scenario in year 1999. For both PM-10 and NO_x, the commenter's charts appears to be based on emissions data from Table G-5 of Attachment G of the DEIR. However, Table G-5 assumes that the Hunters Point Power Plant would be operated by a new owner of that plant under the A-Max scenario (i.e., at a reduced cost for natural gas). In contrast, the DEIR air quality analysis derives from emission data shown in Table 4.5-26, which assumes that PG&E would continue to own and operate the Hunters Point plant and would operate that plant at minimum levels to meet the San Francisco Operating Criteria, as explained in footnote "c" of that table. Instead of the values depicted on the commenter's charts, the DEIR values for the A-Max scenario in 1999 are 727 tons per year of PM-10 and 8,699 tons per year of NO_x.

It is noted that emissions estimates can be presented in various forms, such as tables or charts. The DEIR used the former, while the commenter requests that the former be supplemented with the latter in the Final EIR. Either form is adequate; thus, no supplementary charts have been prepared. However, since all comment letters become part of the Final EIR, the particular charts prepared by the commenter will become part of the Final EIR.

F21 As discussed in the DEIR in the third paragraph on page 4.5-61, the project was found to cause some increase in emissions of criteria pollutants relative to existing and baseline cases. It is also noted in the same paragraph that these emissions are covered by existing air permits with the local air pollution control district. These existing permits already require the operator of a pollution source to both monitor its emissions and regularly report those emissions to the permitting agency. It is primarily by these means that these agencies ensure compliance of permitted sources with applicable air quality standards. These emissions data are available from these agencies for public review. The commenter expresses concern that actual emissions from the sources might exceed those stated in the DEIR and seeks some means of ensuring that this not occur. Since two of the fundamental bases for the analysis of air quality impacts from the project are that the Analytical Maximum capacities represent very conservative measures of potential future plant operations and that the sources could and would not exceed their permitted emission levels, this by itself assures that actual emissions would not exceed those stated in the DEIR.

F22 In the 2005 cases reported in Tables G-2 and G-8, the results for the entire Bay Area bubble are 0.017 lb./MMBtu, so the plants would comply with the overall ceiling. These cases are in the form of "no project" cases, which assume retention of the "air bubble" option under BAAQMD Regulation 9, Rule 11, and use of such option by PG&E. In addition, these results are conservative because they include NO_x emissions occurring during startup, which are not charged against the ceiling. The energy consumed during startup typically is equivalent to one to two full hours of operations and, because SCRs cannot be employed during most of the startup sequence, inclusion of startup emissions increases the average NO_x emission rate overall. The degree of impact, of course, increases with more frequent startups.

The commenter is correct with respect to interpretation of the results of the Analytical Maximum cases reported on Tables G-6, G-9, and G-17. Even when the effects of startups are eliminated, and even assuming that a modified "bubble" may be used to simultaneously encompass the Pittsburg and Contra Costa plants, the NO_x emission rate would still exceed the projected ceiling rate of 0.018 lb./MMBtu. This would mean that the new owner of the Pittsburg plant would have to either reduce production or install further emissions controls, or a combination of both, in order to stay in attainment with its air quality permit. For example, in the instance of Pittsburg Unit 1, a new owner would have to choose between installing increased NO_x emission controls on the unit and/or reducing the unit's peak level of operations significantly. The latter case would also involve coordinating Pittsburg Unit 1 operation at its permitted lower levels of generation with the operations of the other remaining Pittsburg units in a manner that would ensure that the hourly total NO_x emissions from the entire plant remain below 0.018 lb./MMBtu. While the new owner would have several options from which to select as to how to comply with the emissions limitations, the new owner would have no choice but to comply with these limitations.

F23 The DEIR did consider special circumstances for significance criteria. Even though the power plants proposed to be sold would continue to be governed by existing air quality permits, and would operate within the parameters of such permits, the EIR did not assume that compliance with all regulations would automatically mean that the project's impact on air quality was less than significant. Particularly in light of agency and community concerns over air emissions and potential health impacts, the five significance criteria shown on page 4.5-50 and 4.5-51 were used to analyze the air quality effects of the project.

F24 Significance criterion #1 on page 4.5-50 of the DEIR distinguishes between two different circumstances. Under circumstances where the background concentration of a given pollutant is less than the corresponding ambient air quality standard, the ambient air quality standard itself becomes the significance criterion. Under circumstances where the background concentration of a given pollutant is greater than the corresponding ambient standard, a concentration-based threshold identified under Prevention of Significant Deterioration (PSD) provisions is used as the significance criterion. In the Bay Area, the second circumstance applies to PM-10. (Note that standards for ozone are also violated in the Bay Area, but PSD provisions do not contain an ozone threshold. This is because ozone is evaluated in a fundamentally different way using emissions estimates rather than dispersion modeling techniques. It should also be noted that PSD provisions do not directly apply to the project because the project would not require the power plants to apply for new air quality permits. Specific PSD provisions are used to provide a quantitative basis for evaluating qualitative significance criteria listed in the CEQA Guidelines.)

Under the second circumstance, PSD concentration-based thresholds were used as the significance criteria, because such thresholds provide the basis for evaluating dispersion modeling results (which are also defined in terms of concentrations). PSD provisions are included in BAAQMD Regulation 2, Rule 2, which is known as New Source Review (NSR). NSR also includes emissions-based criteria (e.g., pounds per day), but such criteria cannot be directly compared to concentration estimates.

The DEIR does, however, cite additional significance criteria, some of which are emissions-based. Significance criterion #2, for example, cites the BAAQMD-recommended emissions-based criteria for evaluating the significance of emissions increases from indirect sources. The *BAAQMD CEQA Guidelines* distinguishes between indirect sources, such as autos and trucks, which do not operate under BAAQMD permits, and direct sources, like power plants, which generally do operate under BAAQMD permits (BAAQMD, 1996). The emissions-based criteria cited as significance criterion #2 apply to indirect sources, not to direct sources. The DEIR air quality analysis adopts the BAAQMD approach.

Finally, page 4.5-51 of the DEIR describes significance criterion #5, a criterion developed specifically for this DEIR to address the issue of "nonattainment." It achieves this purpose by linking power plant emissions changes to corresponding emissions forecasts contained in the BAAQMD's *'97 Clean Air Plan*. The *'97 Clean Air Plan* was prepared specifically to address regional "nonattainment" for the state ozone standard, but it also contains PM-10 emissions forecasts and control measures that would address PM-10 concerns as well (BAAQMD, 1997).

F25 The concentration-based PM-10 significance thresholds cited in the discussion of significance criterion #1 on page 4.5-50 of the DEIR were derived from BAAQMD Regulation 2, Rule 2, paragraph 2-2-233 (Significant Air Quality Impacts, PSD).

F26 The 210 tons per year of NO_x as shown in Table 4.5-26 is the best estimate of minimum operations at the Hunters Point Power Plant in light of PG&E's agreement with the City and County of San Francisco. This number was determined by an updated run of Table G-18. This is the amount that was used for the Hunters Point plant in the air quality analysis. While the emissions from the Hunters Point plant are relevant background (i.e., baseline) data, they were not used to determine significance because they are not part of the proposed project and are not expected to change from the 1999 baseline numbers. Table G-1 is a 1999 Baseline that assumes that the Hunters Point plant would sell power into the PX, when economically possible, in addition to just meeting reliability needs of the ISO to support the San Francisco peninsula.

F27 Please see responses to Comments U14 and U22.

F28 Please see responses to Comments U14 and U22. The photochemical models mentioned (CAM_x; the Comprehensive Air Quality Model and UAMV, the nested grid version of the Urban Airshed Model) are competing tools used primarily for ozone modeling for the development of regional and statewide air quality plans. The UAMV model is used by the U.S. EPA to determine State Implementation Plan (SIP) compliance. Because of the level of detail that must go into these models (i.e., intense study of meteorological events, and data from all sources) and resulting uncertainty that is implicit in such models, they are generally not used for the analysis of individual projects.

F29 The commenter makes a valid point. The DEIR is revised to eliminate the idea that the cumulative impact can be presumed to be less than significant because the project-specific impact would be less than significant. However, the conclusion of "less than significant" is rooted in other bases. For example, the DEIR on page 4.5-75, first full paragraph, cites the Mission Bay SEIR, which notes that no authoritative regulatory body has adopted any standard to determine whether the risks posed by existing levels of toxic air contaminants should be considered acceptable and, in turn, whether cumulative increases in ambient risks should be considered significant. Without a scientifically accepted methodology or criterion, a conclusion regarding significance of the cumulative impact would be speculative. Some of the difficulty related to determining cumulative toxic effects relates to the methodology of determining Maximally Exposed Individual (MEI) locations and exposure levels for individual projects. This methodology is not practical for a future scenario with multiple regional stationary and mobile sources.

The lack of a criterion for evaluating cumulative air toxics impacts contrasts with criteria air pollutants (e.g., ozone, carbon monoxide, and nitrogen dioxide). With criteria air pollutants, both project-specific and cumulative impacts can be evaluated with reference to particular values, known as ambient air quality standards, since those values represent concentration levels below which public health and welfare effects can be presumed to be negligible. In contrast, the project-specific air toxics criterion of "10 in a million" risk does not represent a "safe" level where public health and welfare effects can be presumed to be negligible, but rather, the "10 in a million" criterion represents a policy decision by the air district as to the circumstances under which it will require emissions control technology of individual stationary sources. In addition, another possible source of cumulative air toxics criteria is the state's Air Toxics "Hot Spots" Information and Assessment Act (AB 2588), Under AB 2588, commercial and industrial facilities emitting air toxics were required to prepare toxics emissions inventories, and based on those inventories, certain of those facilities were required to prepare health risk assessments. Based on the results of the health risk assessments, facilities were placed in one of three categories if their calculated risks exceeded 10 in a million: Level 1 (between 10 and 100 in a million risk), Level 2 (between 100 and 500 in a million risk), and Level 3 (greater than 500 in a million risk). For facilities whose risk levels are calculated to be less than 10 in a million, no formal public notification measures were required; thus, the criterion of 10 in a million is a benchmark under state law to distinguish among facilities on the basis of air toxics. But, once again, it is noted that health risk assessments prepared under AB 2588 are facility-specific and that the categorization is made of each facility individually, not to a group of facilities in a given area on a cumulative basis. As such, the "10 in a million" criterion does not lend itself to cumulative air toxics impact assessment.

Also, it is noted that the project's contribution to the cumulative impact would not be cumulatively considerable. This can be demonstrated by comparing the ambient background risk with the Potrero Power Plant's contribution at the maximally exposed individual (MEI) location. The average background risk from toxic air contaminants was estimated by BAAQMD to be 303 in a million in 1995 (see page 4.5-12 of the DEIR). Eliminating the Potrero plant entirely would reduce the background risk at the MEI location by only 0.2 to 0.3 in a million (see Table 4.5-34 on page 4.5-73 of the DEIR), which essentially would leave the background risk unchanged. Recent changes to the CEQA Guidelines support the conclusion that such a contribution would not mean that cumulative impacts associated with the project would be significant. Paragraph (a)(4) of Section 15130 of the CEQA Guidelines now states that an EIR may determine that a project's contribution to a significant cumulative impact is *de minimus* and thus is not significant. A *de minimus* contribution means that the environmental conditions would essentially be the same whether or not the proposed project is implemented. As explained above, with or without the Potrero Power Plant, the risk from toxic air contaminants in ambient air in the vicinity of the plant would be expected to be on the order of 303 in a million and, therefore, the project's contribution would be *de minimus*.

Page 4.5-75 of the DEIR (first full paragraph) is hereby revised as follows:

> With respect to the cumulative contribution to overall ambient risk from toxic air contaminants in the Bay Area (from all sources, including mobile and stationary), the Mission Bay SEIR notes that no authoritative regulatory body has adopted any standard to determine whether the risks posed by existing levels of toxic air contaminants should be considered acceptable and, in turn, whether possible increases in ambient risks could potentially be considered significant. <u>Without a criterion, a conclusion regarding significance of the cumulative impact would be speculative.</u>
>
> <u>In any event, the project's contribution to the cumulative impact would not be cumulatively considerable. This can be demonstrated by comparing the ambient background risk with the Potrero Power Plant's contribution at the MEI location. The average background risk from toxic air contaminants was estimated by BAAQMD to be 303 in a million in 1995 (see page 4.5-12). Eliminating the Potrero plant entirely would reduce the background risk at the MEI location by only 0.2 to 0.3 in a million (see Table 4.5-34), which essentially would leave the background risk unchanged. The CEQA Guidelines now state that an EIR may determine that a project's contribution to a significant cumulative impact is *de minimus* and thus is not significant. A *de minimus* contribution means that the environmental conditions would essentially be the same whether or not the proposed project is implemented.</u>

> As noted, with or without the Potrero plant, the risk from toxic air contaminants in the ambient air in the vicinity of the plant would be expected to be on the order of 303 in a million and, therefore, the project's contribution would be *de minimus*. ~~The Mission Bay SEIR declines from adopting a significance criterion and, instead, assumes that the cumulative impact on ambient concentrations of toxic air contaminants would be significant since the project-specific impact would be significant. Based on the converse to that concept, the contribution of divestiture to overall cumulative ambient risk would be less than significant because the project-specific impact would be less than significant.~~

In addition, the following paragraph is hereby added after the third full paragraph on page 4.5-74 of the DEIR:

> As discussed below under "Cumulative (2015) Bay Area Analysis," with respect to the cumulative contribution to overall ambient risk from toxic air contaminants in the Bay Area (from all sources, including mobile and stationary), no authoritative regulatory body has adopted any standard to determine whether the risks posed by existing levels of toxic air contaminants should be considered acceptable and, in turn, whether possible increases in ambient risks could potentially be considered significant. Without a criterion, a conclusion regarding significance of the cumulative impact would be speculative. In any event, as explained below, the project's contribution to the cumulative impact would not be cumulatively considerable.

F30 The commenter suggests that additional mitigation measures (e.g., restricting operating hours or requiring air emission offsets) be included in the Final EIR to ensure that air quality impacts will be less than significant. Subsequent to submission of this comment letter, the commenter provided another letter addressing this same issue (see Comment F79). That later, clarifying correspondence requested "a discussion of mitigation measures, to the extent such measures are available or appropriate," and specifically deferred to the CPUC's responsibility to make the determination of whether any additional "mitigation measures are necessary or appropriate." As indicated in the discussion below, it does not appear that such potential additional mitigation measures are necessary or appropriate because they are not needed to address environmental impacts and/or are otherwise infeasible.

As noted in the comment, the DEIR identifies Impact 4.5-5 (inconsistency with the *'97 Clean Air Plan*) as a temporary unavoidable significant impact. Mitigation Measure 4.5-5 would eliminate the inconsistency by 2003. Mitigation Measure 4.5-5 is consistent with the strategy identified by the BAAQMD in Comment Letter E (see the second paragraph of page 1 of its letter dated September 23, 1998). The letter indicates that the BAAQMD is committed to modifying its Regulation 9, Rule 11 so that the rule will continue to apply to these power plants, regardless of ownership. The intent of the modification would be to achieve NO_x reductions at least equivalent to the current rule, with the same emission limits and deadlines as the current system-wide schedule. The modification on oil burning (to minimize PM-10, PM-2.5, and toxic emissions) would be retained.

Limiting operating capacities has been considered for mitigating project effects, but as explained in some of the points below, such limitations would not be necessary or appropriate. Acceleration of the Regulation 9, Rule 11 schedule for NO_x emission rate reductions has also been considered, but has been rejected for the reasons given below. Based on many considerations, the EIR has determined that more restrictive limitations are not warranted to address the temporary inconsistency with the *'97 Clean Air Plan* that would result if the plants operated at their Analytical Maximum capacities. The following points further elaborate on reasons (including policy, cost, schedule, technical and legal issues) that further mitigation (beyond that identified in Mitigation Measure 4.5-5) is not considered feasible.

1) The time available for new owners to evaluate the engineering feasibility and effectiveness of adding pollution control equipment as required by Regulation 9, Rule 11, is already very limited and further acceleration of the schedules in not feasible. Furthermore, the Executive Summary of the October 23, 1995 BAAQMD staff report noted that the amendments to Regulation 9, Rule 11 were designed to allow greater flexibility in complying with the rule to take advantage of new advanced "pollution prevention" low NO_x combustion technology, and to reduce the cost of compliance while maintaining equivalent NO_x reductions. The amendments were not expected to result in any adverse environmental impacts. The BAAQMD indicated that incorporation of advanced low NO_x combustion "pollution prevention" technology could reduce dependence on add-on "tailpipe" technology such as selective catalytic reduction (SCR). Forcing acceleration of emission controls could result in new owners choosing to implement short-term measures, which would interfere with the flexibility to consider longer-term and more effective strategies, such as unit retirement or repowering, that may be ultimately more beneficial to the environment than short term solutions undertaken to address a short-lived impact that is not certain to happen.

2) Complex planning, coordination and technical issues would be raised by any effort to accelerate controls, limit emissions or capacity factors, particularly given the must-run status of the plants and, in the case of the Potrero Power Plant, the role it plays in providing for electric reliability in San Francisco (see DEIR, Section 4.12).

3) The BAAQMD-administered emissions banking system, which provides offsets or "credits," was set up in the context of the issuance or modification of air permits for new or modified stationary sources. In contrast, this project involves existing, permitted sources that may increase their emissions, but these increases would be within the conditions and limitations of existing permits. As such, the project lies outside of the context from which emissions banking was established and therefore, there are no clear rules or guidelines to apply. Use of emissions credits to offset the temporary impact identified for the project would be infeasible. The remedy for the identified potential inconsistency with the *'97 Clean Air Plan* is through revision of

the applicable air rules to ensure their continued applicability (included as a mitigation measure in the DEIR) and through revision of the plan, if necessary, which BAAQMD intends to do as evidenced in its comment letter on the DEIR. It should be noted that more stringent power plant emissions controls would be one of many possibilities under consideration in the event that BAAQMD determines that additional control measures are necessary during the next plan update cycle.

4) It would be impractical to implement a mitigation measure that would affect four power plants (until closed, all emissions from Hunters Point Power Plant would still be considered in determining consistency with the *'97 Clean Air Plan*) that could have as many as three different owners (assuming that Pittsburg and Contra Costa Power Plants are sold as a package). Plan consistency depends upon all Bay Area electric power-generating steam boilers, and such capacity restrictions at four plants would complicate ISO dispatch and could potentially compromise electric reliability.

F31 The impact assessment compares future air quality in 2005 (after 2003) to the existing environment. With the implementation of Mitigation Measure 4.5-5, which requires substantially the form and stringency of the current BAAQMD Regulation 9, Rule 11, NO_x emissions will be reduced from current levels even if the fossil-fueled plants were to operate at their Analytical Maximum capacities. The effectiveness of Mitigation Measure 4.5-5 is portrayed in the following table (Table F31), which summarizes the NO_x data presented in Tables 4.5-23, 4.5-24, and 4.5-25 of the DEIR. The assumptions for the Analytical Maximum scenarios are very conservative so that the Analytical Maximum capacity forecasts do not understate the future maximum operating levels of the plants (please refer also to response to Comment F54).

TABLE F31
NO_X EMISSIONS (TONS PER YEAR)

Power Plant	1999 Baseline	2005 Analytical Maximum without Mitigation	2005 Analytical Maximum with Mitigation
Potrero	389	906	188
Contra Costa	711	1,389	244
Pittsburg	3,000	4,922	1,142

F32 The commenter refers to the 2015 cumulative analysis for carbon monoxide presented in the DEIR. Such analysis was prepared in response to a request by City and County of San Francisco staff to analyze that year as an extension of the (2015) cumulative analysis presented in the Mission Bay SEIR. With respect to concentration estimates, the Mission

Bay SEIR evaluates only carbon monoxide, not the other criteria air pollutants, and thus, the extension of that evaluation in the DEIR evaluates only carbon monoxide.

The DEIR's analysis year for cumulative effects, with the exception noted above, is year 2005. Please see Tables 4.5-29, 4.5-31, and 4.5-32 and the corresponding discussion on page 4.5-70 of the DEIR for an evaluation of cumulative (2005) concentrations of criteria air pollutants, including carbon monoxide, nitrogen dioxide, sulfur dioxide, PM-10, and PM-2.5. The tables mentioned above were prepared with a method designed to account for mobile and stationary sources of air pollution. As explained in footnote "a" in these tables, a conservative background concentration is assumed for the criteria air pollutants by using the 2nd highest value recorded over a three year period at a BAAQMD monitoring station. These values are actual measured values of recent outside air that include air pollutants from all sources. The 2005 cumulative project increment is then added to these background levels. The 2005 cumulative project increment added is for the stationary sources at the power plants because the mobile sources from the power plants are already accounted for in the current background used to project the future background and Section 4.6 (Transportation and Circulation; page 4.6-2) of the DEIR found that possible increases from the project would be negligible in comparison to existing traffic volumes. The inclusion of other cumulative mobile and stationary source emissions in 2005 is accounted for by the conservative nature of the future background concentrations that are used. There is no information to indicate that other future projects would result in creating higher 2005 background levels than are forecasted in the EIR, and, for the most part, criteria air pollutant levels seem to be trending downward in the regions being analyzed.

F33 PG&E's contractor, Fluor Daniel GTI, has completed a Phase II Environmental Site Assessment and Risk Assessment for each plant to be divested, including the Potrero Power Plant. The findings of the Phase II Environmental Site Assessment and Risk Assessment for the Potrero Power Plant are summarized here. Results of the Phase II Environmental Site Assessment and Risk Assessment for the Geysers Power Plant are summarized in the response to Comment T10. Findings of the Phase II Environmental Site Assessment and Risk Assessment for the Pittsburg and Contra Costa Power Plants are summarized in the staff-initiated text changes in Chapter 4 of this document.

Page 4.9-6 of the DEIR (second complete paragraph) is hereby revised as follows:

> PG&E has completed ~~is conducting~~ Phase II testing to determine the nature, extent and potential costs to remediate identified contaminants. A Risk Assessment also was prepared as part of the Phase II report. ~~is in preparation.~~

The findings and conclusions of the Phase II investigations do not modify the analysis nor conclusions of the DEIR. However, page 4.9-6 of the DEIR (following second complete paragraph) is amended as follows to reflect the information presented in Fluor Daniel GTI's Phase II Environmental Site Assessment for the Potrero Power Plant:

The purpose and objectives of the Phase II Environmental Site Assessment for the Potrero Power Plant were:

- to collect and evaluate environmental data on soil, groundwater and sediment conditions at the Potrero Power Plant;
- to use the environmental data collected to perform a Baseline Health Risk Assessment and determine hypothetical cleanup levels on the basis of the findings of the Health Risk Assessment and a review of the regulatory requirements; and
- to develop and present reasonable approaches for remediating impacted soil, groundwater and sediment.

Fluor Daniel GTI performed the following field investigations during the Phase II study:

- drilled 55 soil borings;
- hand augered 8 soil borings;
- collected and analyzed 198 soil samples from the borings;
- collected and analyzed 8 surface debris samples;
- collected 12 offshore sediment samples and analyzed 3 of the 12 samples;
- installed 36 temporary groundwater monitoring wells;
- collected and analyzed groundwater samples from the temporary monitoring wells;
- collected and analyzed groundwater samples from 10 of 13 existing monitoring wells;
- performed slug tests and passive water level monitoring at wells; and
- measured liquid levels in all accessible well points.

Various soil samples were analyzed for volatile organic compounds (VOCs) (EPA Method 8260), polynuclear aromatic hydrocarbons (PAHs) (EPA Method 8310), phenols (EPA Method 8270), total petroleum hydrocarbons (TPH) (EPA Method 8015), polychlorinated biphenyls (PCBs) (EPA Method 8081), metals (EPA Methods 6000, 7000, and 7196), cyanide (EPA Method 9010), asbestos, (EPA Method 600), and general soil chemistry using a variety of methodologies.

Sediment samples were analyzed for PAHs (EPA Method 8310) and TPH (EPA Method 8015).

Surface debris samples were analyzed for VOCs (EPA Method 8260), PAHs (EPA Method 8310), phenols (EPA Method 8270), TPH (EPA Method 8015), PCBs (EPA Method 8081), and cyanide (EPA Method 9010).

Groundwater samples were analyzed for VOCs (EPA Method 8260), PAHs (EPA Method 8310), phenols (EPA Method 8270), TPH (EPA Method 8015), PCBs (EPA Method 8081), metals (EPA Methods 6000, 7000, and 7196), and cyanide (EPA Method 9010).

The Phase II Assessment report presented extensive discussions of the findings of these various analyses. The major areas of potential concern at the Potrero Power Plant, as reported in the Phase II report, include:

- the former manufactured gas plant area, especially the locations of PG&E's current fuel tank farm and the Customer Energy Services / Safety, Health & Claims area, where TPH, metals, PAHs, nitrogen compounds, phenols, and VOCs were found;
- areas of the plant where materials formerly were stored on bare earth, where VOCs, TPH, PAHs, and PCBs were found;
- areas of artificial fill, where VOCs, TPH, PAHs, metals, cyanide, and phenols were found;
- old Station A, where TPH, PAHs, and metals were found;
- former fuel storage sites, where TPH, PAHs, and metals were found;
- former sugar house, where VOCs, TPH, PAHs, metals, and asbestos were found;
- former oil sludge sump site, where VOCs, TPH, and PAHs were found;
- various fuel spills or leaks, where TPH and PAHs were found;
- former diesel dump tank, where TPH was found;
- former paint and solvent storage area, where TPH, PAHs, and metals were found;
- railroad spur area, where TPH and PAHs were found;
- debris on site, where TPH and PAHs were found; and
- groundwater at various locations, where TPH, metals, PAHs, VOCs, and cyanide were found.

Included in the Phase II Assessment report was a Baseline Health Risk Assessment to determine whether concentrations of chemicals detected in soil and groundwater at the Potrero plant present an unacceptable risk to human health and the environment given the assumptions made for the risk assessment. Contaminants of concern were selected on the basis of test results. An exposure assessment provided information on potential receptor populations, potential exposure routes, exposure parameters, algorithms for calculating the exposure dose, and chemical fate and transport modeling.

The exposure assessment considered the following potential receptor populations: on-site plant workers, on-site construction workers, hypothetical site visitors, and hypothetical future recreation users. Exposure routes that were identified included inhalation, incidental ingestion, and dermal contact with soils, groundwater, and surface water.

The results of the Risk Assessment indicated that acceptable risk limits are exceeded for a hypothetical future on-site worker exposed to chemicals of potential concern in surface soil, and for a hypothetical future construction worker exposed to chemicals of concern in groundwater. Chemicals of concern in the soils included benzo(a)anthracene, benzo(a)pyrene, benzo(b)fluoranthene, indeno(1,2,3-cd)pyrene, and dibenz(a,h)anthracene. Chemicals of concern in groundwater included benzo(a)anthracene, benzo(a)pyrene, benzo(b)fluoranthene, benzo(k)fluoranthene, indeno(1,2,3-cd)pyrene, and dibenz(a,h)anthracene. In addition, the results of modeling analysis indicated that arsenic, chromium, cyanide, lead, nickel, selenium, mercury, acenaphthene, acenaphthylene, naphthalene, phenanthrene, and benzene may discharge to the Bay within 100 years.

The conclusions of the Risk Assessment indicated that soil and groundwater remediation should be carried out at the Potrero Power Plant site in order to protect the health and safety of future workers.

On the basis of the findings of the Phase II investigation and the Risk Assessment, Fluor Daniel GTI specified six remedial issues: (1) soil and groundwater contamination in many locations of the central area of the site, primarily including TPH in soil, non-aqueous phase liquids (i.e. liquids that do not mix with water) in wells, and TPH, PAHs, cyanide, and metals in groundwater; (2) potential threats to San Francisco Bay water quality from non-aqueous phase products in several wells, and from carbon-rich debris at various locations; (3) petroleum hydrocarbons in groundwater; (4) cyanide in groundwater; (5) unused conduits to the Bay; and (6) PAHs and metal contamination in shallow soil.

Remedial alternatives were presented in the Phase II report for each remedial issue. The findings and conclusions of the Phase II investigation and the Risk Assessment do not modify the analysis nor the conclusions of this section.

Refer to Comment F36 for the proper Phase II reference citation.

F34 Page 4.9-1 of the DEIR (paragraph 1) is hereby revised as follows:

> ...the Asbestos Hazard Emergency Response Act; Proposition 65; and the Toxic Substances Control Act.

Page 4.9-3 of the DEIR (at end of Regional Setting) is hereby amended with a new paragraph as follows:

> Pertinent local ordinances that regulate hazardous materials and hazardous waste include San Francisco's Hazardous Materials Ordinance, which provides for safe handling of hazardous materials in the City; San Francisco's Underground Storage Tank regulations, which require cleanup of underground tank sites at the time of tank removal; and San Francisco's Maher Ordinance, which mandates a site history study, a soil testing report, and a remediation plan prior to excavation in certain areas of the City built on fill.

As the commenter noted, summaries of environmental conditions at each plant were not included in the Regional Setting section of the DEIR. These summaries are instead provided individually in the Local Setting, Section 4.9.2. For the Potrero Power Plant, the discussion of local environmental conditions begins on page 4.9-3.

According to information presented in the Phase I Environmental Site Assessment for the Potrero Power Plant, the plant site currently has no underground storage tanks. (This information can be found on page 5-11 of the Phase I report.)

The presence of subsurface PAHs at the Potrero plant site is known and was mentioned in the DEIR on page 4.9-5 (bottom paragraph), and again on page 4.9-6 (second full paragraph). PAHs were reported in the Phase II Environmental Site Assessment report for the Potrero Power Plant, as is described in the response to Comment F33.

F35 The presence of asbestos-containing materials and PCBs at the Potrero Power Plant had been noted as "material recognized environmental conditions" in the Phase I Environmental Site Assessment for the Potrero Power Plant. This was mentioned on page 4.9-6 (second full paragraph) of the DEIR. Asbestos-containing waste and PCB-containing waste at the Potrero Power Plant are handled according to existing hazardous waste regulations. For a discussion of the findings of the subsequent Phase II Environmental Assessment, please refer to the response to Comment F33.

For a discussion of lead-based paint, please see the response to Comment F47.

Electromagnetic fields are discussed separately as Impact 4.9-6 of the DEIR, which is found on page 4.9-24.

F36 Page 4.9-25 of the DEIR is hereby amended with the following additional reference:

Fluor Daniel GTI, *Phase II Environmental Site Assessment: Potrero Power Plant*, prepared for Pacific Gas and Electric Company, San Francisco, California, June 1998.

Also please see the response to Comment F33.

F37 No remediation schedule for the Potrero Power Plant site has been set as yet.

F38 The PEA done by PG&E for the Potrero Power Plant discussed hazardous materials and potential site contamination at the plant site. (This discussion can be found on pages 4-85 through 4-87 of the PEA.) Pertinent information presented in PG&E's PEA regarding hazards is included in the DEIR in the discussion of potential site contamination beginning on page 4.9-5. The PEA found that the site does not pose any current hazards to human health or the environment.

F39 The current status of the "material recognized environmental conditions" at the Potrero Power Plant remains as described in the DEIR on page 4.9-6. For a discussion of site information presented in the subsequent Phase II Environmental Assessment, please refer to the response to Comment F33.

F40 PG&E performed the Phase II Site Assessment and the Risk Assessment for the Potrero Power Plant site voluntarily. The relationship between the Phase I Assessment, Phase II Assessment and Risk Assessment is discussed in the DEIR on page 4.9-15 (third paragraph). PG&E was not directed to prepare these documents by a regulatory agency.

The need for site cleanup on the basis of risks to human health or to the environment is to be determined by the findings of the Risk Assessment, as is described in the DEIR, page 4.9-17. This Risk Assessment has now been completed, as is discussed in the response to Comment F33. Cleanup would be done in accordance with remediation plans drawn up by PG&E's remediation contractor, in consultation with the San Francisco Department of Public Health and the San Francisco Bay Regional Water Quality Control Board. A timetable for cleanup would be prepared at that time.

F41 Environmental contaminants are known to be present at the plants to be divested, but cleanup of contamination on private property is required by government agencies only if, in the judgment of those agencies, the contaminants pose a threat to site occupants, to public health, or to the environment. At present, such conditions do not occur at the Potrero Power Plant or at any of the other plants to be divested. Divestiture, therefore, is the primary process that is promoting accelerated cleanup at these plant sites.

Divestiture is expected to accelerate remediation because site cleanup has been factored into, and is an integral part of, the divestiture process. PG&E has been planning for remediation since the divestiture process was initiated. The Phase I and Phase II Environmental Site Investigations have been completed and published, remedial options have been developed and are under discussion, and funds have been set aside by PG&E to pay for the cleanup. All of these actions were taken with divestiture in mind. PG&E has assumed responsibility for legally required remediation of all existing areas of contamination at the plants, as is discussed in the DEIR starting at the bottom of page 4.9-16.

Please also see the response to Comment F42.

F42 The California Environmental Protection Agency (Department of Toxic Substances Control) or the San Francisco Department of Public Health could require site remediation if either agency determined independently that conditions at the Potrero Power Plant posed a threat to public health or to the environment. The San Francisco Bay Regional Water Quality Control Board could require site remediation if it determined that conditions at the Potrero Power Plant posed a threat to water quality. The Department of Toxic Substances Control is currently overseeing the Potrero plant site with respect to environmental issues.

Other laws, ordinances, and regulations, including asbestos regulations, lead-based paint regulations, San Francisco's Maher Ordinance, the City's underground storage tank regulations and so on, control the scope and extent of cleanup work at active project sites, but do not trigger site remediation *per se.*

Should PG&E's Risk Assessment and subsequent agency discussions determine that site remediation is warranted at the Potrero Power Plant, the "Site Designation Process Under the Unified Agency Review of Hazardous Material Release Sites" would be used to guide the process. This is described on page 4.9-17 of the DEIR (top paragraph).

Also please see the response to Comment L36.

F43 The divestiture process has included the identification of site contamination as part of due diligence, as witnessed by the Phase I Environmental Site Investigation, the Phase II Environmental Site Investigation, and the Risk Assessment. The findings of the Phase II report and Risk Assessment for the Potrero Power Plant are summarized in the response to Comment F33. Under terms of the Purchase and Sale Agreement, PG&E has agreed to be responsible for any legally required remediation of existing contaminated soil and groundwater at the divested plants and therefore will be financially responsible for such remediation activities. Current "must-run" provisions will be considered in remediation planning. The determination of which particular remediation strategies will be ultimately pursued, and how such strategies relate to system reliability, will not be affected by divestiture. The issue of how remediation activities are carried out while system reliability is maintained will need to be addressed regardless of who owns the Potrero Power Plant when such activities are undertaken.

F44 The current situation at the Potrero Power Plant regarding site contamination was described in the DEIR starting on page 4.9-5. Supplementary information generated by the Phase II Environmental Site Assessment is summarized in the response to Comment F33, above.

This setting information indicates that the Potrero plant site does have areas of contamination, and that those areas have been contaminated for years. Although PG&E has accepted responsibility for cleanup of existing contamination, PG&E would have little incentive to accelerate environmental cleanup without divestiture. Even though the Department of Toxic Substances Control is overseeing the Potrero plant site with respect to environmental issues, PG&E is currently under no regulatory mandate to perform remediation.

With regard to costs, all funds necessary to perform remediation would be set aside in advance through the divestiture process. The fact that PG&E has accepted responsibility for site cleanup means that the new owners will not have to pay any of the remediation costs for soil and groundwater contamination existing prior to sale. Divestiture would not create any new potentially responsible parties as to existing contamination.

Divestiture is expected to promote timely and efficient site remediation. The Phase I and Phase II investigations were driven by the divestiture process. Please refer to the response to Comment F41 for further elaboration on why divestiture will promote remediation.

Regarding possible loss of access to records, all environmental documentation is being provided to bidders as well as to interested public agencies, thus divestiture is not expected to result in "loss of access to records," as stated by the commenter. Under Mitigation Measure 4.9-3, PG&E will provide to the new owner copies of all safety-related documentation. Although the new owners will be responsible for ensuring that their operations are in compliance with applicable laws, this informational material may assist new owners in understanding worker health and safety issues and procedures and in meeting all safety and legal obligations regarding hazardous materials handling, emergency plans and storage. For further clarification, the bolded Mitigation Measure 4.9-3 that appears on page 4.9-21 of the DEIR, and in Table S.2 on page S-36 of the DEIR, is hereby revised as follows:

> For the plants subject to this proceeding, PG&E shall provide the new owner~~s with copies of all safety-related documentation.~~, for each respective plant, with all of PG&E's material, non-privileged informational materials and training documents (not including records relating to PG&E personnel) regarding worker health and safety, emergency plans and hazardous materials handling and storage. This material shall be indexed and organized in a manner that is readily accessible to the new owner.

Because the above information is now reflected in the mitigation measure statement, the first sentence of the first full paragraph on page 4.9-21 of the DEIR is hereby deleted.

F45 The commenter is concerned that "PG&E's proposed responsibility for cleanup could be transferred, diluted, or avoided as a result of the divestiture unless PG&E enters into binding remediation commitments prior to sale."

Each purchase and sale agreement for the plant sites will specify all cleanup provisions for which PG&E is assuming responsibility. Each purchase and sale agreement will be reviewed by the CPUC prior to its approval of the sale, ensuring that PG&E's commitments to remediation will be spelled out in the agreement and understood by all parties involved, and will be enforceable.

The CPUC review process will ensure that PG&E complies with the environmental responsibilities. Remediation will be done by PG&E under full regulatory agency oversight. As is described on page 4.9-17 of the DEIR, the appropriate lead agency at each plant would be selected by means of the "Site Designation Process Under the Unified Agency Review of Hazardous Material Release Sites."[6] Moreover, Mitigation Measure 4.9-1 requires PG&E to provide to the CPUC written evidence that the Risk Assessment has been provided to not only the buyer of the plant, but to the Department of Toxic Substances Control, the local county health department, and the relevant Regional Water Quality Control Board (RWQCB).

Also, please see the response to Comment F41.

F46 Page 4.9-19 of the DEIR (first bulleted paragraph) describes the properties of petroleum-based products; the paragraph is hereby revised as follows:

> Power plants typically store petroleum products for fuel, lubricants, <u>solvents, degreasers, oils,</u> and other uses.

Page 4.9-20 of the DEIR (bulleted paragraphs) is hereby amended to include the following:

- <u>Sodium bisulfite ($NaHSO_3$). Sodium bisulfite is a mild chemical reducing agent. It is relatively non-toxic, as bisulfite is commonly used as a food preservative. Some individuals experience an allergic reaction when they ingest food containing bisulfite ions. Sodium bisulfite is used at power plants to dechlorinate cooling water; the bisulfite removes any excess hypochlorite remaining in the water after the once-through cooling water pass. In pure form, sodium bisulfite is a white, crystalline solid with a slight sulfurous odor. Routes of exposure include inhalation of dust or direct contact. At the plants, it is formulated in aqueous solution. Concentrated solutions of the chemical could be irritating to skin and mucous membranes. Sodium bisulfite is nonflammable, but it emits toxic fumes when exposed to fire or is heated to decomposition.</u>

- <u>Sodium hypochlorite (NaOCl). Sodium hypochlorite is a moderately corrosive oxidizing agent. Typically, it is handled in aqueous solutions having a mild "chlorine" odor. Sodium hypochlorite is the active ingredient in household bleach; its oxidative property whitens clothing, but can also cause fabrics to fade or discolor. It is toxic to aquatic life, and is used for</u>

6 *California Health and Safety Code*, Division 20, Chapter 6.65, January 1, 1997.

chlorination of cooling water at power plants that use a once-through cooling system. It acts to prevent algae and residual buildup on the inside of the condenser tubes. It is mildly toxic to humans and can cause irritation of skin, eyes, and mucous membranes upon direct contact.

See the response to Comment N47 for additional amendments to page 4.9-20 of the DEIR.

F47 The commenter expresses concern regarding the presence of lead-based paint at the Potrero Power Plant. Lead-based paint is no longer used at the plant, but some surfaces are still coated with lead-based paint that was applied years ago. Lead-based paint can therefore be considered a potential site contaminant.

Page 4.9-6 of the DEIR (middle of the page, at the end of the Potential Site Contamination section) is hereby amended as follows:

Lead-based paint was not mentioned as a recognized environmental condition in the Phase I Environmental Site Assessment, nor was it identified as a problem in the Phase II Environmental Site Assessment. However, lead-based paint is found on equipment throughout the Potrero Power Plant. Lead, a heavy metal, is toxic to humans when ingested repeatedly, particularly to young children. When lead-based paint adheres to the surface of the materials it covers, it poses little health risk and is not considered to be a hazardous waste. Delaminated or chipped lead-based paint, however, can cause a potential human health threat if the paint chips are ingested. Lead dust, which can also be inhaled, may present a possible health risk to construction workers and the public during demolition of a structure covered with lead-based paint. Lead-based paint that has separated from a structure could also contaminate nearby soil.

Prior to any demolition work at the Potrero Power Plant, a paint survey would be required to identify the locations and quantities of lead-based paint, as well as the lead content of the paint. If the survey were to identify lead-based paint, the plant would be required to comply with applicable federal, state and local requirements for the handling, removal, and disposal of lead-based paint and lead dust. The key applicable requirements include the federal OSHA, Cal/OSHA, and BAAQMD regulations, CCR Title 22 regulations relating to the disposal of lead-containing wastes, San Francisco's Hazardous Materials Ordinance, and Chapter 36 of the City's Building Code.

Chapter 36 of the San Francisco Building Code establishes requirements for property owners and contractors who engage in activities that remove or disturb lead-based paint on the exteriors of buildings and steel structures. The ordinance contains performance standards, including establishment of containment barriers that are at least as effective at protecting human health and the environment as those in the most recent *Guidelines for Evaluation and Control of Lead-Based Paint Hazards* promulgated by the U.S. Department of Housing and Urban Development. Under

Chapter 36, any building completed prior to 1978 is presumed to have been painted with lead paint unless proven otherwise.

Specific elements of this ordinance, implemented and enforced by the San Francisco Department of Building Inspection, include a requirement for a containment barrier around any work involving lead paint. For activities involving abrasive blasting, hydroblasting, scraping, or sanding of lead-painted exterior surfaces, a HEPA (high-efficiency) vacuum may be required. Burning, torching, or similar activities are prohibited. Following completion of work involving lead paint, all visible lead paint contaminants must be removed from the work site. In addition, the ordinance requires the notification of the Department of Building Inspection and posting of a sign at the work site where lead paint is being disturbed.

As plant conditions warrant, lead-based paint at the Potrero Power Plant is abated and handled in accordance with all applicable regulations. When handled properly, lead-based paint is not considered a hazard.

F48 As is described on page 4.9-21 of the DEIR, PG&E intends to provide the new owners with all of PG&E's nonprivileged informational materials and training documents regarding worker health and safety, emergency plans, and hazardous materials handling and storage. This disclosure will be made during the bidding process.

The commenter has misunderstood the "three day" provision of Mitigation Measure 4.9-3. The requirement "at least three business days prior to transfer of title" that is specified in the mitigation measure refers only to the disclosure form to be signed by the new owner documenting that the mitigation has been performed as required.

Furthermore, as is described on page 4.9-21 of the DEIR, PG&E personnel will continue to operate the divested plants for two years after the sale, which would give the new owners ample time to familiarize themselves with the documents.

F49 The issue that concerns the commenter—proper disposal of hazardous waste generated by remedial activities—would be covered in the Site Remediation Plan that guides each cleanup. The Site Remediation Plan would be subject to review by the lead agency. Divestiture would act to accelerate the process of remediation, but would not change the amount of waste that would ultimately result from any remediation.

Page 4.9-17 of the DEIR (first full paragraph, first sentence) is hereby revised as follows:

For each location to be remediated, PG&E intends to prepare a Site Remediation Plan that will specify measures to be taken to protect workers and the public from exposure to potential site hazards and certify that the proposed remediation measures would clean up the contaminants, properly dispose of wastes generated, and protect public health in accordance with federal, state, and local requirements.

F50 The nature and significance of electromagnetic fields, including a summary of CPUC policy regarding this issue, are discussed in the DEIR under Impact 4.9-6 on page 4.9-24. Electromagnetic fields are not power plant "emissions." As is discussed in the DEIR, the existence of electromagnetic fields generated by electrical equipment does not constitute a significant project impact that would require mitigation. The reduction of EMF field using no- and low-cost methods as proposed by the commenter is applicable to newly constructed or upgraded utility facilities. The divestiture of the power plants does not include new or upgraded facilities

F51 The list of projects presented in Table 5.1 was originally provided by PG&E on April 2, 1998. Within a week prior to publication of the DEIR, each of the planning jurisdictions, including the San Francisco Planning Department, were contacted to update the list. Consequently, Table 5.1 was up to date as of publication time. In response to the comment, the San Francisco Planning Department and the Port of San Francisco were contacted and an additional list of projects was obtained. As noted below, these projects have been added to Table 5.1. Please see response to Comment F52 for a discussion of an updated cumulative effects analysis.

Table 5.1 of the DEIR (page 5-12) is hereby amended to include the following additional projects known or anticipated by the San Francisco Planning Department and the Port of San Francisco:

Project Name	Description
Potrero Power Plant	
<u>MUNI Diesel Coach Operating Division Facility</u>	<u>The project would relocate a MUNI diesel coach operating facility from Fisherman's Wharf to Indiana Street at Islais Creek. The facility would house the storage, dispatch, and fueling of a fleet of 165–200 buses. During Phase I, scheduled to begin in 1999, a 66,000-square-foot building would be constructed for bus maintenance, offices, and training facilities. The 5.32-acre site would also include bus parking and washing and fueling facilities. Phase II would occur on an adjacent 2.4-acre parcel and would include construction of more maintenance facilities and bus parking. This application also includes a temporary relocation of MUNI's Woods bus maintenance facility to a site immediately adjacent to the MUNI Diesel Coach Operating Division Facility. This property would be used by MUNI for one to two years while the Woods facility is renovated. (Case No. 88.700E)</u>
<u>CrushCom</u>	<u>This project includes a concrete/rock-crushing operation, with recycling of the aggregate. It is currently crushing concrete debris from the recently-demolished Geneva Towers. CrushCom has a 5-year lease to operate on the Port of San Francisco's Western Pacific Opportunity Area, a waterfront site bounded by Illinois Street on the west, 25th Street on the north, Cesar Chavez Street on the south, and the Bay on the east. (Case No. 97.711E)</u>

Project Name	Description
MUNI Metro East	Located on the western half of the Western Pacific Opportunity Area described above, this project entails construction of a maintenance and storage yard for light rail cars associated with the MUNI Third Street Light Rail Project. The project entails development of the 13-acre site with a maintenance facility, tracks, overhead electric lines, and a storage yard for up to 100 light rail cars. The project would relieve crowding at an existing facility at San Jose and Geneva Avenues. It would be constructed in two phases, with the first phase (constructing facilities for 60–70 cars) beginning construction in 2001 and ending in 2002. Environmental review of this project is covered in the EIR/EIS for the Third Street Light Rail Project. (Case No. 96.281E)
NORCAL West Coast Recycling Facility	NORCAL will utilize an existing warehouse located on Pier 96 to ship recycled materials to foreign markets. NORCAL has signed a multi-year lease from the Port of San Francisco for use of the property. The San Francisco Planning Department's Office of Environmental Review determined on July 21, 1998 that this project was categorically exempt under CEQA.
USA Coach	USA Coach proposes to relocate its bus operations currently located in the South of Market area of San Francisco to Pier 96. The company is currently in lease negotiations with the Port of San Francisco. The proposed project would be a bus maintenance and storage facility that would be located in an existing shed on Pier 96.
Mission Valley Rock Operation	This project entails shipment of concrete rubble from an existing bulk cargo terminal at Pier 92. This lease with the Port of San Francisco represents a continuation of bulk cargo use that has been ongoing at Pier 92 for decades.
Tidewater Sand and Gravel Facility	This project is an expansion of the existing sand and gravel operation on Pier 92 that Tidewater Sand and Gravel has been carrying on since 1981. The company extracts sand and gravel from the Bay and dries it on site. The project, approved in April 1998, expanded the company's lease boundary, providing them more space to pile drying sand and gravel.
Bedrock RediMix	This existing operation on Pier 90 is a concrete batch mixing facility. The terms of the lease were amended to add 10,000 square feet to the existing 30,000 sq. ft. of leased space and to extend the three-year lease an additional five years. The project is intended to improve the operator's efficiency, but does not entail any increased operations. (Case No. 95.319E)
ASL Private Storage	This project entails moving an existing private mini-storage facility from Mission Bay to Pier 90. Sea-going cargo containers will be placed on a currently vacant 127,000-square-foot paved lot.

Project Name	Description
Specialty Crushing, Inc.	This 90,000-square-foot concrete-crushing facility has been operating on Pier 94 since January 1996, recycling construction debris from the demolished Embarcadero Freeway. Their lease has expired and they are currently operating on a month-to-month basis. It is currently unknown whether the company will apply for a new lease. (Case No. 94.109E)

F52 The updated list for the Mission Bay/Potrero/Bayview-Hunters Point area includes a wide variety of projects. Some are very small in size and would clearly have a negligible impact on air quality. Others are larger in size, such as the Bayview-Hunters Point Redevelopment Area and Mission Bay projects, but would generate PM-10 primarily through mobile sources. Mobile-source emissions of PM-10 would be distributed over a wide geographic area, not just in the immediate vicinity or even just in San Francisco. The geographic area of impact would be defined by the locations of the origins and destinations of individual vehicle trips generated by these projects. In other cases, the projects themselves would reduce the number of stationary PM-10 sources by converting industrial land uses into residential or commercial land uses.

However, among the projects listed in Table 5.1 (as supplemented in response to Comment F52), there are six that would have the potential to significantly affect local PM-10 concentrations because they include stationary sources that could potentially generate substantial amounts of direct PM-10. These six projects include: (1) the Construction and Building Materials Supply Center at Piers 90 and 92, which would include a concrete recycling facility and two ready mix batch plants; (2) the RMC Lonestar Pier 90 Lease, which would include a concrete ready-mix facility; (3) Crushcom, which would include a concrete/rock-crushing operation; (4) Tidewater Sand and Gravel Facility, which would extract sand and gravel from the Bay and dry it on site; (5) Bedrock RediMix, which would include a concrete batch mixing facility; and (6) Specialty Crushing, Inc., which would include a concrete crushing facility.

PM-10 emissions generated by these projects would depend upon a number of variables including the exact industrial processes to be used, the size of the equipment and machinery, and the amount of material throughput. Also, PM-10 emissions and corresponding cumulative PM-10 concentrations would be affected by conditions and limitations set forth in air permits issued by BAAQMD. Unlike the projects generating only mobile-source emissions, these projects would include substantial new stationary emissions sources, and as such, these projects would be subject to BAAQMD regulations that will require implementation of Best Available Control Technology (BACT) and may also require offsets if certain trigger levels would be met. BACT, in this context, could include use of fine sprays or filters or other techniques to reduce direct PM-10 emissions.

Since the variables cited above and the specific emissions controls that would be required by BAAQMD are unknown, an estimate of the cumulative PM-10 concentration from these six sources cannot be made at this time. However, given BAAQMD's regulatory authority and control over the PM-10 emissions sources associated with these projects, it is not clear whether their cumulative effect would be significant. Nonetheless, when further defined, these projects would be subject to separate, project-specific environmental review by the City and County of San Francisco and/or the Port of San Francisco and other agencies with jurisdiction over their operation, at which time the potential for these impacts to occur would be fully evaluated.

The local background concentrations of PM-10 do occasionally exceed the 24-hour state standards and the project would contribute PM-10 to the environment. However, the small additional amount of PM10 contributed by the project should not be considered cumulatively significant even in light of the arguably serious nature of the already existing problem. Furthermore, the state 24-hour PM-10 standard is only one-third of the federal 24-hour PM-10 standard. By adopting the more restrictive standard, California has increased the controls on PM-10, but this strict standard is being met in only one county (Lake County) of the 58 counties in California. In light of the recently reviewed federal 24-hour PM-10 standard (which remains 150 $\mu g/m^3$), a background level of 50 $\mu g/m^3$ may not be a severe environmental condition.

In any event, the proposed divestiture's contribution to cumulative PM-10 impacts would not be cumulatively considerable. Recent changes to the CEQA Guidelines support the conclusion that just because the total of the proposed divestiture in combination with other cumulative projects (in addition to the background concentration) would be above the 24-hour state PM-10 standard, 50 $\mu g/m^3$, does not mean that the project's contribution to a significant cumulative impact is cumulatively considerable and, thus, significant. Paragraph (a)(4) of Section 15130 of the CEQA Guidelines now states that an EIR may determine that a project's contribution to a significant cumulative impact is *de minimus* and, thus, is not significant. A *de minimus* contribution means that the environmental conditions would essentially be the same whether or not the proposed project is implemented.

Table 4.5-29 shows that PM-10 concentrations would be higher under the 2005 Cumulative Analytical Maximum scenario than the 1999 baseline conditions. However, since the modeled cumulative increase (difference between the two scenarios) in local PM-10 concentrations would essentially be the same with or without the project's negligible contribution of 0.8 $\mu g/m^3$, the project's contribution to any significant cumulative impact would be considered *de minimus* given that the background concentration is estimated to be 57 $\mu g/m^3$. Because this project would result in less than a 1 $\mu g/m^3$ increase on the maximum day (which is even less than the PSD annual average significance limit), the effect of the project is clearly *de minimus* with respect to PM-10. On this basis, it is determined that the project would not result in a cumulatively considerable impact to local PM-10 concentrations. It is also that the 5.0 $\mu g/m^3$ significance threshold used in the DEIR for evaluating PM-10 concentration impacts was used in determining the significance of PM-10 impacts in the CEC's decision on the San Francisco Energy Company's

Cogeneration Project (Docket No. 94-AFC-1). The CEC decision notes that U.S. EPA characterized the 5.0 μg/m^3 increment as the "level below which it would not require any impact analysis on the ground that such impact levels are simply insignificant, even 'in [the] most stringent regulatory context (i.e., the 24-hour average).'"

F53 The likelihood that new owners of the fossil-fueled plants would tend to operate at higher levels than PG&E, and the methods used to evaluate this potential change, are discussed in the DEIR in Chapter 3. Refer to Section 3-5 for discussions of the factors that could produce change as a result of divestiture, including incentives for new owners to operate at higher levels.

The commenter argues that subjective considerations were used to develop the concept of the "Analytical Maximum" scenario that were used in the analysis. However, the Analytical Maximum case was carefully developed in the DEIR to take into account all three possible reasons for future higher operation rates by new owners: the portfolio effect, fuel procurement practices, and the new owner's ability immediately to participate in the direct access market. As to the portfolio effect, the modeling assumed that the plants were owned by single owners. Regarding direct access, the modeling assumed that the new owners would have the opportunity to participate in that market. The model assumed that low gas prices would simulate extraordinarily beneficial fuel procurement practices.

The Analytical Maximum case was developed to represent a very high, but still plausible, level of hourly operations consistent with each plant's forced outage rate and maintenance schedule. On an hour-by-hour basis, the Analytical Maximum would not violate the reliability constraints (e.g., scheduled outages for maintenance), supply/demand constraints, or transmission constraints that could never be intentionally ignored in the real world. In balancing hourly loads and resources it was assumed that, regardless of new ownership, generation from the divested plants would not be able to displace must-run, must-take hydro, and very low-priced coal-fired generation. Thus, the Analytical Maximum scenario was employed to determine a realistic maximum level of generation for a new owner whose operations rate would always be constrained by demand for electricity.

The most straightforward way to implement each Analytical Maximum forecast presented in the DEIR was to lower the hypothetical fuel cost so much that operation of the fossil-fueled plants being divested would essentially be preferred over all other fossil-fueled plants not being divested. The lower gas prices reflect not only potential access to discounted gas contracts, but also lower transaction and cycling costs due to greater potential for direct access sales and a lack of a generation portfolio to support cycling operations. (Please see the response to Comment E2 for additional information.) These assumptions produced an Analytical Maximum level of operations that was reduced from each plant's physical maximum only to a degree necessary to reflect inviolate, real-world impediments.

In any event, in the case of the Potrero Power Plant, the Analytical Maximum and the physical maximum cases would be very similar. In neither case can the three combustion turbines (CTs) run more than 10 percent of the time due to BAAQMD rules. It is implausible that the CTs would operate even as much as 10 percent of the time because they run on diesel, must continue to contribute to the demands of the San Francisco Operating Criteria, and are dispatched as Must Run Category C units by the ISO. The physical maximum capacity factor for the Potrero 3 boiler unit in 1999 would be 88 percent when forced and planned outages and deratings are taken into account. Thus, the physical maximum possible capacity factor for the entire Potrero plant (including the CTs) would be 54.6 percent, only about 10 percent higher than the 1999 Analytical Maximum case. In this instance, because the Potrero plant operating at its physical maximum would produce such a small amount of additional generation when viewed in the context of the State of California as a whole, the Analytical Maximum is not very much less than the physical maximum and certainly captures the maximum potential environmental impacts of divestiture.

F54 Please see the response to Comment F53. The Analytical Maximum capacity factors used in the DEIR are less than the corresponding physical maximum values. The physical maximum, however, is not an appropriate measure to use in analyzing project effects because of its real-world implausibility. The likelihood of a plant running at its physical maximum is nil given the system constraints, the limitations on electricity demand (e.g., low demand in the middle of the night limits plant potential output), and the economic considerations faced by any owner.

In addition, calculating the physical maximum might be done easily, but the results could not easily be incorporated into the SERASYM™ model to assess hypothetical cumulative impacts. The analytical maximum takes into account system constraints and therefore is realistic; the physical maximum does not and is not.

F55 The commenter notes that we live in a changing world and that “very little with respect to the PX and ISO stays constant these days.” It is agreed that the operations of the PX/ISO may change in the future. However, no plausible potential changes of which the EIR preparers are aware would do away with requirements for system reliability or with the objective of procuring minimum cost generation. The case evaluated in the Analytical Maximum scenario in the DEIR considered that plant operations would increase to an extent that would fully capture any credible foreseeable changes in system operations. Please see the responses to Comments F53 and F54.

F56 The modest transmission modifications that PG&E is now completing with respect to imports into the City are reflected in the 1999 Baseline and the 1999 Analytical Maximum cases. These are described in the DEIR in Chapter 3 and summarized on pages S-7 and S-8.

More significant transmission projects are reflected in the 2005 Cumulative Impacts case entitled “Variant 1.” This variant is described in the DEIR on page 3-13, bottom paragraph. It is also explained in Table 5.2 in the DEIR, starting on page 5-17 (refer to note “e”). The results of the 2005 Cumulative Impacts case, including all variants, are presented in the DEIR in Table 5.2.

F57 The commenter correctly acknowledges that there is uncertainty as to where and when new power plants will be added to the power grid in the western region. Chapter 5, Cumulative Impacts, of the DEIR, addresses the potential for environmental impacts to occur from the development of new power plants in combination with the divested PG&E power plants in 2005. Specifically, Section 5.2.2 (pages 5-3 to 5-7 of the DEIR) discusses reasonably foreseeable future power plant development throughout California (including new generation to replace the Hunters Point Power Plant in San Francisco). In recognizing the uncertainty surrounding the development of these plants, the DEIR states on page 5-5 that “it is unknown at this time which of these power plants, if any, will eventually be constructed.” To avoid underestimating the localized effects of the proposed project together with cumulative projects, most of the power plants that are discussed in Section 5.2.2 as proposed new plants were excluded from the detailed cumulative modeling and analysis on pages 5-16 to 5-42 of the DEIR. First of all, the development of these plants was considered to be too speculative to include them in the analysis. Secondly, as described on pages 5-2 and 5-7 of the DEIR, development of new power plants would increase the overall generation capacity in California, thereby decreasing the likelihood that the plants proposed for divestiture would operate at higher levels in the future. As described on page 5-2 of the DEIR, the exception to this premise is that all future projects deemed necessary to support localized demand for electricity by 2005 are carried forward into the analysis. The discussion under Section 5.3, Potential Cumulative Impacts, on page 5-16 of the DEIR, summarizes those power plants that are assumed to be developed under the various cumulative scenarios.

As mentioned above, the DEIR explains that an increase in overall generating capacity resulting from the development of new power plants would decrease the tendency of new owners of the divested power plants to increase operations at such plants. This suggests that an increase in the number of new power plants being developed would result in a decrease in generation at the divested power plants. Conversely, the development of fewer new power plants would increase the tendency for the new owners of the divested plants to maximize the operation of those plants. This concept is illustrated in Table 5.2 (pages 5-17 and 5-18 of the DEIR), which shows annual plant capacity factor estimates for each of the four plants being divested under various cumulative scenarios. Of the three cumulative scenarios shown in Table 5.2, the Variant 2 scenario represents the scenario with the greatest overall generating capacity in terms of number of plants and the size of plants. When compared to the basic 2005 Cumulative Analytical Maximum, the annual plant capacity factor at each of the divested power plants decreases. If the excluded power plants described in Section 5.2.2 were included in the modeling, it is anticipated that the annual plant capacity factor of the divested plants would be even lower than is shown in Table 5.2.

Following publication of the DEIR, subsequent SERASYM™ modeling was completed for San Diego Gas and Electric Company's (SDG&E) proposed divestiture of its electric generating facilities, a refueling facility and long-term power supply contracts. The results of these modeling efforts are presented in SDG&E's *Mitigated Negative Declaration and Initial Study California Public Utilities Commission, San Diego Gas and Electric Company's Application No. 97-12-039, Proposal for Divestiture*, published on October 13, 1998. The analysis determined that because of increased transmission capability into the San Diego region, not known at the time of DEIR publication, the proposed Otay Mesa Power Plant described in Section 5.2 of the DEIR would not be need to meet projected demands. The modeling completed for SDG&E's proposed divestiture showed that the removal of the Otay Mesa Power Plant, in addition to other system-wide upgrades, resulted in no increase in capacity factors at the PG&E plants being divested from the capacity factors presented in the DEIR. In summary, the conclusions of these more recent modeling efforts would not affect the conclusions in the DEIR.

F58 Section 3.4 of the DEIR (pages 3-4 and 3-5) (not of Attachment C) must be read in context with Section 3.5 of the DEIR. Section 3.4 does not list these factors "as too speculative to consider at this time." Section 3.4 lists and discusses the types of factors that could produce environmental change, e.g., changes in the amount of energy generated at a particular plant or in the number of employees at such plant. Section 3.5 then describes the DEIR's assumptions concerning the changes that divestiture would reasonably foreseeably effect, e.g., new owners having a tendency to generate more electricity than PG&E. The Analytical Maximum capacity factors go beyond capturing these reasonably foreseeable changes so as to conservatively depict the potential impact of the project.

F59 The analysis to the extent feasible accounts for the possible range in changes from restructuring. Attachment C discusses the rationale for how the effects of restructuring were separated from those of divestiture, and how the incentives of new owners might differ from those of PG&E. Note that the sentence quoted by the commenter relates to restructuring, and not to divestiture.

F60 The commenter suggests that the use of the physical maximum in the Final EIR would capture all of the effects of changes in operating mode and fuel costs, rendering use of the Analytical Maximum unnecessary. Please see the responses to Comments F53 and F54 regarding the Analytical Maximum and physical maximum concepts.

The change in fuel prices that was used in the Analytical Maximum case was misunderstood by the commenter. The fuel price used in the analysis was 25 percent cheaper than the cheapest natural gas projected to be available in California in each month considered. In each month of 1999 and 2005 where the Analytical Maximum estimates were made, the cheapest gas was projected to be available to the Cool Water plant in the Mojave desert. This projection is due to the near complete absence of inter- and intra-state gas transmission charges. Since gas service to the plants projected for divestiture incurs much larger gas transportation charges, the forecasted monthly price of natural gas fuel for the PG&E plants proposed for divestiture are significantly higher in the basecase. Thus, the reduction in fuel price employed in the Analytical Maximum cases was significantly more than 25 percent below (depending upon the month and year) the fuel price assumed in the baseline case if PG&E were to retain the plants.

In addition, the operational studies using the Analytical Maximum scenario have already been completed, making the suggested implementation of the physical maximum an unnecessary exercise that would not affect the conclusions of the DEIR.

F61 Please see the responses to Comments F53 and F54. The commenter provides no reasonable rationale for why use of the hypothetical physical maximum could more accurately account for future uncertainties in plant operations. On the other hand, the DEIR analysts, CPUC staff, and commenters have not identified any scenario that would allow future generation levels to exceed the Analytical Maximum scenario that was evaluated in the DEIR. The Analytical Maximum approach yields a realistic upper bound on possible generation without considering the highly implausible physical maximum levels of generation.

F62 The approaches used in the DEIR to address the health impacts from exposure to increases in PM-10 and PM-2.5 emissions go beyond those typically carried out under CEQA. The levels chosen were not based on administrative rules, but were based on levels that have shown to cause statistically significant health effects. EIRs usually compare the estimated concentration increases with the ambient air standards to test for significance. This was done in the EIR when comparing increases from divestiture with baseline emissions to determine if the project would contribute to a violation of a standard. In the case of particulate matter, background measurements indicated that the state PM-10 standard has already been exceeded on occasion. Therefore, the significance threshold identified in significance criterion #1 (see DEIR page 4.5-50) was used, which is based on the BAAQMD definition for a measurable contribution to a standard violation. For criterion #1, the significance threshold is 5 micrograms per cubic meter for a 24-hour average increment and 1 microgram per cubic meter for an annual average increment.

To be conservative, the DEIR also compares contributions from the entire plant emissions (existing emissions plus emissions from divestiture) with PM-10 increases that are considered to cause significant health effects based on relative risk coefficients for particulate matter exposure. Although the DEIR did not use a rigid statistical approach, the preparers relied on the information on relative risks that were reported by EPA in the Particulate Matter Criteria Document (USEPA, 1996a) and in the EPA-OAQPS Staff Paper (USEPA, 1996b) to determine if the contributions from the plants would result in acceptable levels. The PM-10 concentrations reported in the DEIR are for worst-case receptors and are not indicative of typical exposure levels in the region. Average levels around the plants, which are actually more representative of public exposure, are about one-tenth of these maximum levels. This is principally because the public is usually not located within the prevailing wind direction from the plants. The DEIR does not ignore the breadth of human health effects related to particulate matter exposure. It does not state that there is a threshold below which there are no impacts, nor does it reject the possibility of a linear dose-response effect extrapolated to zero, even though the studies cited in the literature do not conclusively reject the potential for a threshold exposure level (see USEPA, 1996a, Vol. III, pp. 12-22 through 12-24). Instead, the DEIR relies on the information pertaining to relative risk coefficients reported in the literature to establish exposure levels that may cause significant health effects. The ranges showing significant effects were increases of 20 to 50 $\mu g/m^3$. There is even greater uncertainty when increases range from 10 to 20 micrograms per cubic meter. This uncertainty is described further in response to Comment F74.

References:

U.S. Environmental Protection Agency, *Air Quality Criteria for Particulate Matter*, EPA/600/P-95/001cF, April 1996a.

U.S. Environmental Protection Agency, *Review of the National Ambient Air Quality Standards for Particulate Matter, Policy Assessment of Scientific and Technical Information*, EPA-452/R-96-013, July 1996b.

F63 The impact analysis used the ambient air standards which are health-based. Therefore, it was not necessary to carry out separate risk assessments for the criteria pollutants. For criteria pollutants, such as PM-10, that already exceed the state ambient air standards, strict limitations on concentration increases which are related to measurable thresholds as identified in the BAAQMD PSD regulation were used to determine whether the project would cause health effects. Since the ambient air standards for the other criteria pollutants (NO_2, SO_2, and CO), which are health-based, were not exceeded as a result of the project, the health effects were considered less than significant.

F64 The DEIR focused on the worst-case potential impacts from plant emissions, which involved local receptors. The modeled impacts from the plant emissions on receptors farther away in the region were found to be considerably lower than the local impacts and thus do not require further analysis.

F65 The DEIR focused on the worst-case off-site receptors at residences and at locations that included sensitive receptors, such as schools. Since the modeled concentrations at these receptors were found to be less than significant, levels at sensitive receptors farther from the plants would be even lower. Therefore, further analysis for all exposed populations was not carried out because the levels are less than significant. Please also see response to Comment F67 regarding identification of exposed populations.

F66 The approaches used to assess the health effects from the project considered the most sensitive health outcomes. For toxic substances that are not criteria pollutants, the EIR used the methods consistent with AB 2588. For criteria pollutants, the ambient air standards were used to assess impacts, since they are health-based standards. For criteria pollutants that occasionally exceed an ambient air standard, such as particulate matter, more restrictive concentration increases were used, based on measurable concentration thresholds and relative risk coefficients. However, studies in the literature that are cited in the EIR show large variations and uncertainties in relative risks for various endpoints, especially for moderate increases in particulate matter. Since the relative risks for many of these endpoints overlap, the risks for all endpoints were grouped together, and the general term “respiratory-related health effects” was considered in the DEIR. Various health effect endpoints from exposure to particulate matter were described on pages 4.5-7, 4.5-31, and 4.5-32 of the DEIR.

F67 Based on discussions with staff at the BAAQMD in determining the proper CEQA analyses, it was agreed that population health burden should not be included in the analysis, because of uncertainties in the population demographics and greater uncertainties in estimating actual exposure by these populations. Instead, it was agreed that the EIR should focus on the maximum incremental risk at the worst-case receptor and to determine if the estimated increases are significant.

F68 Studies cited in the literature indicate that health impacts from acute and chronic exposure to particulate matter are closely related. The EPA Criteria Document states that long-term exposure often reflects the net sum of acute events that took place in a year (USEPA, 1996, V III, P 12-138 and 12-139). Thus, long-term (chronic) health effects associated with exposure to particulate matter are likely to reflect some combination of acute and chronic effects.

The paragraph in the DEIR referred to in the comment describes some of the effects of exposure to particulate matter. It was not intended to provide an exhaustive description of all of the health effects, many of which are very similar. The literature cited in the paragraph in the DEIR are examples of the numerous studies that have been carried out. Many of these studies relied on the same data sets with slightly different interpretations. The EPA Criteria Document for particulate matter and the EPA Staff Assessment report are good compendia of these studies. The last paragraph on page 4.5-7 is hereby amended as follows to include these compendia:

> Several studies that EPA relied on for their staff report have shown an association between exposure to particulate matter, both PM-10 and PM-2.5, and respiratory ailments or cardiovascular disease (Pope *et al.*, 1992; Thurston *et al.*, 1992; Burnett *et al.*, 1995). Other studies have related particulate matter to increases in asthma attacks (Whittemore and Korn, 1980; Pope *et al.*, 1991). In general, these studies have shown that short-term and long-term exposure to particulate matter can cause acute and chronic health effects. <u>The EPA Criteria Document and the EPA Staff Report on Particulate Matter (USEPA, 1996a, and 1996b) are compendia of the many studies related to health effects from particulate matter exposure.</u> Fine particulate matter (PM-2.5), which can penetrate deep into the lungs, causes more serious respiratory ailments. These studies, along with information provided by

EPA in the 1996 staff report, were used as the basis for evaluating the impacts of PG&E emissions of PM-10 and PM-2.5, on public health.

F69 The following language is hereby added to the end of the last sentence of the first full paragraph on page 4.5-12 of the DEIR:

…<u>(pages 4.5-26 through 4.5-32).</u>

The commenter also requests that Appendix G be cross referenced for risk assessment methodology information. Upon inspection, there is no risk assessment or methodology information contained within Appendix G and, thus, no further response is required.

F70 As related to the wind rose (Figure 4.5-2 of the DEIR) for the Potrero Power Plant, the nearest residences and population centers are located to the west and southwest (e.g., Potrero Hill) and south (e.g., Bayview/Hunters Point) of the plant sites. This can be seen to some extent on Figure 2.2 and, for the immediate plant vicinity, Figure 4.1-4 provides local zoning designations surrounding the site. Per the predominate winds shown on Figure 4.5-2 (southwest, west-southwest, west and west-northwest), the areas downwind of the site are all off-shore in San Francisco Bay. Only a few percent of the days annually are winds observed that would cause the nearby population centers to be down wind of the power plant (i.e., winds from the east). Please see the response to Comment 4-2, for which a special wind rose was developed further illustrating this point. The commenter suggests that the approximate population sizes of these areas be stated. Population data is presented in Section 4.2.2 of the DEIR on the local population size for the Potrero area.

F71 The sentence was intended to give a general description of some of the potential effects of exposure to particulate matter and was not intended to include all possible health effects. However, it does identify both respiratory and cardiac related effects as possible outcomes. A more comprehensive description is given earlier in the document (DEIR page 4.5-7, third through fifth paragraphs) in which both acute and chronic respiratory effects and cardiovascular effects are identified. The sentence in the DEIR that is referred to by the commenter identifies mortality as one of the outcomes from exposure to particulate matter, and was not intended to downplay this potential effect.

F72 The sentence referred to (second full paragraph on page 4.5-31 of the DEIR) does not state that only areas with high short-term levels of particulate would result in health effects. It does cite several prominent studies that show health effects in cities during air pollution episodes. In several of these studies, short-term (24-hour average) levels exceeded 300 micrograms per cubic meter. The statement in the second paragraph that refers to typical annual average background levels ranging from 18 to 58 micrograms per cubic meter in these cities is not inconsistent with the high particulate matter levels that were observed during episodes. These differences between annual average concentrations and high short-term levels are typical for many urban areas.

The second sentence of the second full paragraph on page 4.5-31 of the DEIR is amended as follows:

> ~~Most~~ Many of these studies have shown relationships between particulate matter exposure and cardio-pulmonary effects during air pollution episodes in major metropolitan areas, where daily ambient air concentrations exceeded 300 micrograms per cubic meter ~~μg/m~~^{3}.

F73 Page 4.5-31 of the DEIR (third full paragraph) is hereby amended as follows:

> "A draft ~~study~~ report released by the Bayview Hunters Point Health and Environmental Assessment Task Force (Aragon and Grumbach, 1997) reported that 1992 hospitalization rates for asthma, hypertension, diabetes and congestive heart failure ~~are~~ were higher in ~~this area~~ Bayview Hunters Point than any other part of San Francisco. However, the draft study ~~does~~ did not identify the cause(s) of the observed increased respiratory problems, and ~~does~~ did not consider individual pollutant exposure. To better understand the causes of the increased ~~incidences~~ hospitalization rates, a detailed study would have to be carried out..."

F74 By citing the relative risks that were reported for a 20-25 microgram per cubic meter increase in PM-2.5 concentration, the DEIR does not reject the possibility of a linear relationship between exposure and health effect, although the EPA Criteria Document on Particulate Matter (USEPA, 1996a) indicates that the interpretation of specific concentration-response relationships is the most problematic issue when determining if the response is linear. This is due to the absence of clear evidence on the mechanisms for various health effects at lower concentration exposure levels (USEPA, 1996a, p. 13-87). Although most models assume a linear, no-threshold underlying relationship that potentially extend to zero concentrations, the existing data do not rule out the possible existence of an underlying non-linear, threshold relationship. The studies reported in the EPA Criteria Document indicate that there is considerable variability in the relative risks with estimates varying by a factor of 5 when concentration increases of 10 micrograms per cubic meter are considered. Information in the Criteria Document showed less variability in relative risks for a 20–25 microgram per cubic meter increase. In addition, Volume III of the Criteria Document (pages 10A-12 through 10A-17) states that total respiratory tract deposition of particulate matter reaches a minimum in the size range between 0.2 microns and 1.0 micron. The information on deposition in the Criteria Document is confirmed by another study (Raabe, 1984). This is important because it is the size range expected for a considerable portion of particulate matter emissions from gas-fired steam boilers (U.S. EPA, 1998). In effect, of all particle sizes, these particles are the least likely to be trapped in the lungs and the most likely to be expelled from the lungs during breathing. This information adds to the uncertainty of health effects from exposure to emissions from gas-fired boilers at the PG&E units, although this factor would reduce concern from particles of this size.

In choosing levels that could be used to judge the health effects from the project emissions, the EIR followed the methods used by EPA when establishing new fine particulate matter standards. In its Policy Assessment of Scientific and Technical Information for Particulate Matter (USEPA, 1996b), the Office of Air Quality Planning and Standards states on page VII-1:

> A final decision (on PM-2.5 standards) must draw upon scientific information about health effects and risks, as well as judgments about how to deal with the range of uncertainties that are inherent in the scientific evidence and analyses. The Staff's (EPA) approach to informing these judgments is based on a recognition that the available health effects evidence generally reflects a continuum consisting of levels at which scientists generally agree that health effects are likely through lower levels at which the likelihood and magnitude of the response becomes increasingly uncertain. This approach is consistent with the requirements of the NAAQS provisions of the Clean Air Act and with how EPA and the courts have historically interpreted the Act. These provisions do not require the Administrator to establish NAAQS at a zero-risk level but rather at a level that avoids unacceptable risks and, thus, protects public health with an adequate margin of safety.

With regard to evaluating the significance of changes in plant operations due to divestiture (direct project impacts as opposed to total plant operations), the more restrictive significance criterion #1 was used (as defined on page 4.5-50 of the DEIR), in which 24-hour PM-10 concentration increases exceeding 5 micrograms per cubic meter was considered to be significant.

CEQA analysis depends upon determining what is a significant environmental impact and does not assume that any increase is significant, even if the increase is linear or could be linear. With this in mind this EIR does not use a standard that a one particle increase in PM-10 would be a significant impact. Rather, the EIR uses significance standards based on concentrations that have shown more certain health effects.

Reference:

Raabe, O., *Deposition and Clearance of Inhaled Particles*, chapter in *Occupational Lung Disease*, Gee, J, K. Morgan, and S. Brooks, Editors, Raven Press, 1984.

F75 The PM-10 significance criteria mentioned on numbered item 1 on page 4.5-50 are taken from BAAQMD Regulation 2, Rule 2 as mentioned in the second sentence of that DEIR paragraph. Thus, there is no need to modify this text.

F76 Please see response to Comment F74 for the first part of the comment regarding how 24-hour average and annual average significance criteria were selected. The significance levels identified in the comment were used to evaluate the consequences of total plant operations (existing plus project impacts). The cumulative effect is included, since the EPA information on relative risks coefficients was based on concentration increases over typical urban background levels, which included other sources.

The increases for PM-10 are not less than those for PM-2.5. They are the same, because it is assumed that all of the emissions from the plant are less than 2.5 microns. The incremental increases mentioned in the comment regarding criterion #1 are for both PM-10 and PM-2.5. The increases referred to in criterion #1 are related increases from divestiture as compared with the baseline environmental conditions. The concentration increases identified in criterion #1 are more restrictive than criterion #4, because #1 deals with emissions changes from the divestiture project, whereas #4 includes total plant emissions (baseline plus divestiture. The response to Comment F74 provides an explanation on the rationale for choosing the numerical targets, and it cites the documents that were relied upon.

The comment regarding the number of days exceeding 20 micrograms per cubic meter refers to Tables 4.5-30 and 4.5-33 in the DEIR. These tables show the number of days that the contributions from the plants (baseline plus divestiture) are expected to exceed certain intervals. The frequencies on the tables identify the number of days in a year that specified threshold levels would be exceeded at the worst-case receptor if a year of daily operations were input to the model. The year of daily operations was derived from SERASYM™ model runs based on energy demand. Tables 4.5-30 and 4.5-33 show that there are no days in which the 20 microgram per cubic meter threshold would be exceeded.

F77 The change in designation for the national ozone standard does not affect significance criterion #5 (on page 4.5-51 of the DEIR) since that criterion was developed to assess consistency of the project with the *'97 Clean Air Plan,* which was prepared to address the nonattainment status of the Bay Area with respect to the more stringent state ozone standard, not the national ozone standard.

F78 The PM-2.5 values shown in Table 4.5-29 represent the specific time period and the value added to the representative background value. For example, 1999 Baseline PM-2.5 values listed in Table 4.5-29 as 1.2/1.2 indicate that, for the first value of 1.2, the expected 1999 Baseline value for Potrero would be 1.2 µg/m3. The second 1.2 indicates that the Potrero plant contribution, when added to the background value of "ND" (i.e., no data), is also 1.2 µg/m3. Any confusion stems from the fact that there are no values currently available for PM-2.5 backgrounds, and there will be none available for several years until the BAAQMD completes its initial PM-2.5 monitoring program. To eliminate any confusion, Table 4.5-29 (and similar values for Tables 4.5-31 and Table 4.5-32) is hereby amended to read as follows:

For particulate matter (PM-2.5), 24-hour values for the following columns are all changed to read:

1999 Baseline	1999 Analytical Maximum	2005 Cumulative Analytical Maximum
1.2/<u>ND</u> ~~1.2~~	1.7/<u>ND</u> ~~1.7~~	2.0/<u>ND</u> ~~2~~

F79 Please see responses to Comments F30 and F31.

September 18, 1998

Mr. Bruce Kaneshiro
Environmental Science Associates
225 Bush Street, Suite 1700
San Francisco, CA 94104

Subject: Comments on Draft EIR for PG&E's Application for Authorization to Sell Certain Generating Plants and Related Assets - Application No. 98-01-008

Dear Mr. Kaneshiro:

Thank you for providing the East Bay Regional Park District ("District") with a copy of the Draft EIR for the subject project. We have review the EIR and provide the following comments for consideration by the California Public Utilities Commission.

[Begin G1]
As noted in the Draft EIR, the District has a variety of existing and proposed park and trail facilities in the East Bay that are in close proximity to two of the generating plants that are proposed for sale. These two plants are the Pittsburg and the Contra Costa Power Plants. It does not appear that the sale of the Contra Costa Plant would have an adverse effect of District facilities, however, sale and reuse of the Pittsburg facility may have the potential to adversely affect our park facilities at Bay Point, near Pittsburg.

The District recently obtained a grant from CALFED for the planning and design of a tidal marsh restoration project that is focused on restoring and enhancing habitat for the Delta smelt. As noted on page 4.78-35 of the Draft EIR under Impact 4.7-2, cooling water system operations of the Pittsburg facility may adversely affect the success of this restoration project. Any change in operations of this facility that would affect the availability, quality, temperature or salinity of the discharge waters could have an adverse affect on Delta smelt and other special-status fish species in the vicinity of our Bay Point facility. These potential effects and suitable mitigation measures should be carefully evaluated in the EIR and the Section 10 permit analysis.
[End G1]

Thank you for the opportunity to comment on the draft EIR. I you have any questions, please contact me at (510) 635-0138 extension 2622.

Sincerely,

/s/

Brad Olson
Environmental Specialist

G. EAST BAY REGIONAL PARK DISTRICT

G1 The impacts of future changes in operation, such as increased generation, at the Pittsburg Power Plant will either fall under the provisions of the National Pollutant Discharge Elimination System and Section 10 effluent limitations, or the new owners will have to apply for new permits. In either case, discharges from the power plant will be controlled by the Regional Water Quality Control Board, the U.S. Fish and Wildlife Service, and other regulatory agencies.

September 21, 1998

Mr. Bruce Kaneshiro, Project Manager
c/o Environmental Science Associates
225 Bush St., Suite 1700
San Francisco, CA 94104

Re: Draft Environmental Impact Report comments, CPUC Application #98-01-008
Geysers Geothermal Power Plant & Other Divestitures

Dear Mr. Kaneshiro:

District staff has reviewed the referenced document sections related to the air quality issues involved in the pending sale of the PG&E Geysers Power Plants. The District asks that major concerns identified below and the specific comments provided in Attachment #1 be addressed in the final EIR. The background information provided regarding the pending sale and the potential new owners is informative, as are the discussions regarding the various projections for continued operations under the various scenarios, but we do consider them incomplete. We are concerned about conceptual errors and the avoidance of identifying any suggestion of mitigation for the scenarios chosen in the DEIR.

Major Concerns

[Begin H1]
Our major concern continues to be the possibility of plant management under a new owner incompatible with maintaining the integrity of the steamfields. The document should emphasize repeatedly that adverse air quality impacts in Lake County are largely a result of the operations of the applicant's power plants, and when the plants are not operating, the associated steamfields located in Sonoma and Lake counties. [End H1] [Begin H2] There are a number of reasons for our concerns in this regard for the Sonoma County units including less advanced technical designs, aged equipment, differing operating conditions and poorer steam quality among others. [End H2]

[Begin H3]
The issue of avoiding steam stacking is extensively noted, however we need to emphasize any condition which results in the atmospheric release of untreated steam is at issue and the cumulative impact of well field bleed flows at well pad locations is of equal or greater concern due to the closer proximity to residents, because of poor plume rise and reduced pollutant dispersion. Additionally, when steamfields are extensively curtailed, well

maintenance including the need for deep drilling rig utilization and increased numbers of well blow downs to remove water or rock bridges all contribute to increased emissions.
[End H3]

[Begin H4]
The “must run” contracts have been offered as a reason that hydro or other curtailments should not be a significant concern. Yet, must run class “B” may be needed only a few hours per year (Pg. C-ii). This needs to be clarified as to how effective it is and what to expect in the future as regards to the minimum power generation available to the steamfield owners. Apparently, except for Units 5-8, it is just a peak temperature requirement and is unlikely to be relevant to hydro curtailment. Please clarify and explain.
[End H4]

[Begin H5]
The situation as presented in the DEIR included a reference to a less than 2.2¢/KW power cost and periods of zero price during the present year. Please explain how this will similarly affect the Geysers’ need for a minimum production to avoid steam venting. If that can not be ensured in the future, consider the below scenario and suggested mitigation for inclusion in the EIR.
[End H5]

[Begin H6]
Were AB 1890 funds used to stabilize the price, and if so at what level? Was the price driven down because of abnormally high availability of hydro power? What is considered an economic price? If you conclude as indicated at the 9/15/98 meeting that this is unlikely because of the price of power and the production cost, state and support your assumptions clearly in the EIR. AB1890 apparently provides limited funding to stabilize pricing during the transition years. Will this funding be available to the new owners, or once they are sold will they be considered merchant plants? How significant is the loss of resources of PG&E whom still has a virtual monopoly on customers and extensive hydro power?
[End H6]

Given the above discussion, please consider the following scenario and suggested mitigation for comment.

Scenario #1

[Begin H7]
Identified Potential Impact: The market economy is such that generation units are prevented from selling the power to the PX and no direct customer delivery is possible. The plant owners shut down all the plants to zero production. The units then must stack, by-pass and/or close in the steamfield with resulting water logging of wells, thermal stress and production well failure. The impact on air quality, water quality and the land is

significant from the vented steam and emissions associated with repair (none of the emissions are necessarily stacking). The steamfields become less profitable and threaten the overall viability of electrical power generation and a loss of this green power resource.

Suggested Mitigation: Ensure that a minimum production is allowed and deliverable from each of the two facilities (Lake & Sonoma). Methods to accomplish this could include: 1) a reserve of approximately 50 and 110 Megawatts at the ISO being set aside specifically for the Lake and Sonoma Geysers plants respectively that would be under a must run continuous agreement; 2) requiring the purchaser (and future purchasers) to operate the facility using a continuous direct purchase customer for at least the sustaining portion of the production; 3) committing the smaller negotiated quantity of generation as a RMRA "A" to include hydro-curtailments; or 4) utilize a distribution benefit charge through the PX/ISO that will support and make viable this minimum production capacity for this specific existing (stranded) green power and ensure that it is bid into the PX (with a general benefit subsidy, if necessary, much like the AB 1890 is now providing).
[End H7]

[Begin H8]
We are in agreement that Alternative 3 (sale to steam suppliers) is likely the environmentally best alternative, provided they have the financial strength to maintain the facilities and this green power remains cost competitive. The District is not in agreement with the conclusions in Table S.2 regarding the air impacts being less than significant, as that assumes an approximate 10% change on an annual basis. This does not consider the significant impact of a single or several individual events. There is no mitigation to assure that the plants will be operated at a level at all times sensitive to preserving air quality.
[End H8]

[Begin H9]
The modeling analysis for the geothermal units predicts emissions variability of between -13% and + 39%, depending on the analysis scenario, with the Sonoma County units accounting for the majority of the increase. Many of these units are approaching their design life span and have higher air emissions potentials due to their date of construction, less advanced technical design, increased maintenance requirements and poorer steam quality. As the emissions from these units predominantly impact the Lake County public, and have been the source of significant air quality complaints and AAQS exceeds in the past, a 40% increase in emissions is considered by the District as significant and thus we would require mitigation. In reality such is not likely to happen unless a choice to change the abatement systems operational techniques is implemented by a new owner, as the abatement systems (especially of newer plants) perform superior to present permit emission limitations. (See Exhibit A attached that lists the permitted and actual emissions as tested recently for units being divested.) Again, this is a case of performance superior to what is required under regulations, especially for the newer units.

Similarly the use of mercury scrubbers (while under permit) are not regulatorily required, since cooperation was high and a variety of incentives existed.
[End H9]

[Begin H10]
The Geysers Air Monitoring Program (GAMP) represents a consortium, and while the regulatory alternative exists, participation is voluntarily renewed by MOU. Present PG&E staff displays a sensitivity and concern for safety, the public and the environment and their programs have clear corporate support. The potential of changing from a monopoly, or to a company without PG&E resources, is of concern.
[End H10]

Given the above discussion please consider the following scenario and suggested mitigation for comment.

<u>Scenario #2</u>

[Begin H11]
Identified Potential Impact: The new owner takes only the steps that are specifically required by permit as an economy measure and decides not to participate in efforts jointly or separately. These efforts include seismic monitoring, air monitoring, the use of an iron chelate catalyst in secondary abatement and the use of mercury scrubbers on the Stretford equipped units. This results in less information on which to document environmental management success, less public trust, greater emission releases and less efficient management approaches to the overall resource area.
[End H11]

[Begin H12]
Suggested Mitigation: Ensure that the new owner participates in GAMP, the seismic monitoring program continues, they continue to use Hg scrubbers and use innovative H2S technologies presently installed.
[End H12]

[Begin H13]
The DEIR is long on discussion but slightly off target as to the interaction of the power plant and steamfield operations. The policy implications of green power also need to be further enlarged upon as part of this first significant green power divestiture decision by the CPUC. The document provides little in finding significance in the divestiture of the subject plant and thus avoids having to recommend mitigation measures. The major issue for the AQMD is not just steam stacking but managing (production assurances) in a manner that ensures the physical integrity of the steamfields without stacking, field wide emission or threatening the long term integrity of field operations and production. We do not believe that we are being overly cautious in attempting to be protective of our air resources and requesting assurances that the Geysers steam resource is adequately protected from misuse and abuse, be it intentional, market driven or unwitting. The

remarks regarding the economic incentive to defer maintenance and utilize plant malfunctions to increase the rate basis is disturbing, and is counterproductive to both resource management and air quality. The knowledge regarding the wise management of the Geysers resources and compatibility with good environmental management has been an acquired learning experience gained over a period of more than 30 years. It is imperative that this knowledge and understanding be retained and that we wisely proceed and assure that this goal is nurtured to the extent possible.
[End H13]

[Begin H14]
We are concerned that this first sale of green power by a monopoly utility is occurring without an assessment of policy or the implications of a lack of policy and we ask that such be incorporated into the EIR as a relevant and necessary part of the scope required. We will not repeat past comments of the uniqueness and environmental advantages of the Geysers and green power in general, as we have all been educated by the past events and prior or existing state policies.
[End H14]

[Begin H15]
In discussions before the Lake County Board and elsewhere, two responses have always come forward from CPUC/ESA staff: 1) that there is a willingness for consumers to pay more for green power, and 2) that the federal legislation gives the Geysers a 1.5-cent/KW advantage. While we hope this is correct, we want such to be clearly and correctly evaluated as part of the EIR.
[End H15]

[Begin H16]
Renewables (green power) are apparently 11% of the present PG&E profile and geothermal is approximately 7% of the total. Is the present niche market for green power that large? Is it likely, given that the label "green power" need only to include 50% green power, that this niche market can adsorb 10-22% of the existing total market? Will the niche market be sustainable in times of a depressed economy? What specifically are the state policies that are in place which recognize the advantages of indigenous green power to our state and country? Please summarize the hidden environmental, national defense, green house gas, economic, and other costs of nuclear and fossil fuel and the advantages to society of nurturing and promoting "green power"? Please at least summarize a response in the final EIR.
[End H16]

[Begin H17]
Please consider in your discussion the timing and status of the CPUC green power certifying/ labeling and emissions disclosure on customer billing; the possibility of an ISO distribution benefit charge to enhance green power sustainability; reduced charges on the PX exchange; preferential financing; lessening the PX buy in cost; and other suggestions as are contained in the National Association of State Energy Officials

"Energy Efficiency and Renewable Energy Sources: A Primer" dated July 1998. These issues in are relevant to our society and should be relevant to the CPUC decision to approve the sale with or without mitigation.
[End H17]

Sincerely,

Robert L. Reynolds, APCO

Attachments: Specific Comments
Exhibit A

CC: Board of Directors
Interested Parties

RLK/RLR

Attachment #1
Specific Items of Comment

[Begin H18]
In Tables S.1, S.3, S.5 (and elsewhere) and Table 2.1 (Description of Facilities) there appears to be a significant difference between the projected scenario annual capacity factors for the Lake County units shown which should be elaborated upon. The DEIR states that the Analytical Maximum Scenario is the "conservative" approach and in the case of the Geysers represents a minimum operating level (worst case). While we understand what this is attempting to convey, it is somewhat confusing and represents approximately a 10% reduction in capacity over the no project alternative. The DEIR is vague on the factors which result in this being the "worst case" and does not recommend if this is the minimum level of operation necessary to preserve the existing air quality (Section 3.6.2 end of paragraph 2) or that this will be a regulatory limit imposed on the buyer. This is where the "must run" contract requirements need to be specific enough to ensure that adverse air quality impacts are minimized, or it acknowledged that they are of little relevance.
[End H18]

[Begin H19]
Page 2-26 Geysers Power Plant. Mining was an important historical previous use but has been very limited in the past 40 years to limited aggregate associated with geothermal development and otherwise to recreational prospects. Timber harvests have occurred within the area and the most significant adjacent land uses are recreational, residential and bottled drinking water production.
[End H19]

[Begin H20]
Page 2-35 Geysers Geothermal Field. The Geysers field is more roughly 10 miles long by 4 miles wide although the Known Geothermal Resource Area (KGRA) is more extensive. Surface manifestations of thermal activity occur throughout the area, however it is acknowledged that major early development centered on the Geyser Creek/Geyser Canyon area.
[End H20]

[Begin H22]
Page 2-38 Geyser Power Plant Units (paragraph 3). More correctly, the steam contains hydrogen sulfide and other reduced sulfur compounds which exist in both a dissolved and gas phase. A portion of the hydrogen sulfide remains dissolved in the liquid condensate and is subsequently chemically treated to maintain solubility and prevent "air stripping" in the cooling tower. The non-condensible gas is treated to convert the H2S to elemental sulfur or SO2 using a Stretford or Incinerator system respectively. The elemental sulfur is more commonly produced as a "sulfur cake or slurry" product more so than a molten material (both are elemental sulfur); the SO2 is removed using a scrubber system and the resulting solution re-injected. The description in Table 2.2 contains a better description

of the process. Flow diagrams Figures 2.18 and 2.19 lack the abatement chemical inputs. Abatement system failures on single units in Sonoma County can cause ambient air quality exceeds in Lake County under various conditions.
[End H22]

[Begin H23]
Page 3-12, 3.6.2 1999 Analytical Maximum Scenario (last four sentences of the first paragraph). The 230KV line outage results in simultaneous multiple plant outages and is of concern during coincident periods of poor air dispersion. The District's concern regarding hydro curtailment is acknowledged, however paragraph (3) is a disclaimer that any particular plant may not operate within range of capacity factors cited. The District is also concerned that the plants receive ongoing preventative maintenance and upgrades where feasible to reduce unexpected maintenance, related temporary shutdowns and resultant emissions. Again, analysis on an annual basis misses short term, event driven, emissions impacts.
[End H23]

[Begin H24]
Chapter 4, 4.1.1 Sonoma and Lake Counties - The reference to a "series of geysers" is likely a reference to a "series of geothermal power plants". Retirement residential and related services are also a major factor in the economy of Lake County. This is an important distinction considering the expanded government service requirements and the sensitivity to air pollutants of the receptor population.
[End H24]

[Begin H25]
Page 4.1-4 Geysers Power Plant - While the Sonoma county portion of the Geysers is sparsely inhabited, the Lake County portion is within or adjacent to community residential, recreational (camps, retreats) and rural residential development. We are not aware of any active mining activity other than geothermal resource exploitation.
[End H25]

[Begin H26]
Page 4.2-10 Geysers Power Plant - The comparison of the number of jobs relative to Sonoma County is not representative of the impact on Lake County (where a large proportion of the workers reside).
[End H26]

[Begin H27]
Page 4.3-6 Geysers Power Plant - Geologic description should include serpentine as a significant rock type present in the Geysers. Serpentine is of concern due to its asbestos content and potential for airborne release.
[End H27]

[Begin H28]
Page 4.5-4 (top of page) Discussion of pollutant transport should emphasize that the regional northwest winds transport pollutants from the Sonoma County power plants into inhabited communities within the Lake County Air Basin (Glenbrook, Pine Summit, Cobb, Anderson Springs, Middletown).
[End H28]

[Begin H29]
Page 4.5-8 Hydrogen Sulfide - Is highly toxic and lethal at concentrations of 1,000 ppm. H2S concentrations in the geothermal steam varies by location, usually in the range of 50 -1,200 ppm. H2S concentrations in the non-condensible gas is within the range of 10,000 - 50,000 ppm.
[End H29]

[Begin H30]
Page 4.5-9 Table 4.5-2 Lake County Air Basin, Particulate Matter (PM-10)[d]. The footnote refers to the new federal PM 2.5 standard. In addition to the PM 2.5 standard, a modified federal PM-10 standard was also retained.
[End H30]

[Begin H31]
Page 4.5-20 Lake County AQMD Regulations, Plans and Policies (first paragraph); The 40 lb/hr particulate emission limit is from the District Rule 411. The source of the cited 15 lb/hr H2S limit is not known and oversimplified. The District has general regulations limiting sulfur emissions from various sources, set at various concentration and mass emission limits. Power plants are subject to New Source Review and Best Available Control Technology (BACT). BACT is project specific and for the existing Lake County units has been defined as emissions of not more than 5 lb/hr H2S per million pounds of steam used. The District's authority to construct and permits to operate further refine and restrict project emissions based on the New Source Review assessment of project emission impacts on the closest receptor.
[End H31]

[Begin H32]
Page 4.5-45 Paragraph (2); The PM-10 monitoring data includes analysis by XRF for the elements cited. Ambient radon concentrations are also measured at the Glenbrook and Anderson Springs sites.
[End H32]

[Begin H33]
Page 4.5-46, Table 4.5-19 "Particulate Matter (PM-10)". Data is available for Glenbrook and Anderson Springs (both located adjacent to and downwind of the Geysers). This GAMP data should be utilized in this table as representative of geothermal impacts.
[End H33]

[Begin H34]
Page 4.5-46 Existing Emissions (first sentence). Include benzene and radon in the category of "other gasses". Geothermal air pollutants are not generally emitted from steam wells, steam transmission lines and steam stacking facilities under normal operations. Steam is emitted during well construction, testing and maintenance operations. Most of the geothermal emissions are from the cooling towers and gas treatment facilities. While well bleeds and well maintenance is currently the largest "steam field" emission source, steam field emissions are relatively insignificant when the power plant is operating.
[End H34]

[Begin H35]
Page 4.5-47, top of page; Most of the air pollutant emissions during normal operations are from the evaporation of the circulating water and "air stripping" which occurs in the cooling towers (provided the gas treatment systems are properly functioning).
[End H35]

[Begin H36]
Paragraph (2): Steam Stacking is more properly a result of the power plant's inability to utilize the available steam rather than a slowdown in use of the steam wells. The "slowdown" is typically an immediate 100% rejection of steam flowing to the plant. While stacking is an immediate and usually short term occurrence, such was not always the case previously.
[End H36]

[Begin H37]
Paragraph (3): Of greater concern now is a condition where a power plant is not operated (for mechanical or perhaps economic considerations) and the steam wells have to be shut-in to a sustaining steam bleed rate consistent with maintaining well integrity for extended periods of time. The cumulative impact of such action has a greater impact potential due to the large number of wells involved, their location closer to residents and the lower air dispersion characteristics of the bleed flows as compared to the massive stacking flow rates.
[End H37]

[Begin H38]
Paragraph (4): Ambient radon measurements continue to be part of the Geysers Air Monitoring Program. The measurements show ambient radon concentrations of 0.3 - 0.5 pico-curies per liter (not 3 -5 pico-curies) and these values are considered background and are within the range of reported background concentrations for many areas in the United States.
[End H38]

[Begin H39]
Page 4.5-49 Tables 4.5-21 and 4.5-22; Since the Geysers Power Plant emissions primarily impact Lake County residents, the Tables would be more descriptive if the emissions were all compared as a percentage to the Lake County emissions inventory.
[End H39]

[Begin H40]
Page 4.5-50 (top of page) ; The reference exposure levels used in calculating risk are currently under review by OEHHA and it is expected that the revised values may result in a significantly higher calculated risk.
[End H40]

[Begin H41]
Page 4.5-60 (Tables 4.5-27 and 4.5-28). Are the Baseline and Analytical Maximum emissions estimates in these tables different than those presented in the Executive Summary and Section 3 where analytical maximum was a minimum capacity factor? Are the emissions factors utilized based on test data or permit limits? If permit limits are the basis, emissions would not be expected to change, if operating data is utilized, do the estimates consider that the new owner will continue to control emissions to less than (at times considerably below) the permit limits? The difference between actual and permitted emissions can be significant. For Lake County Unit #16, actual emissions are approximately 3.5 times lower than allowed by the permit for H_2S and 16.5 times lower for particulate matter. The EIR should address whether or not the new owner will operate the plants similarly. If realized, the projected 40% increase in emissions from the Sonoma County units would appear to be capable of a significant impact. Of greater concern to the LCAQMD is an increase in "uncontrolled" emissions due to economics, reliability or maintenance factors.
[End H41]

[Begin H42]
Page 4.5-75 Geysers Power Plant; Although steam stacking has been shown as a cause of AAQS exceeds the same can be demonstrated for emissions from untreated well bleeds, normal and abnormal power plant operations as separate and cumulative sources. Cumulative steady state "controlled" emissions are capable of, and have been the source of both nuisance complaint generation and AAQS exceeds. These events are typically associated with episodes of regional air stagnation and a "flushing" of built up pollutant concentrations from West Geysers area into Lake County during the early afternoon wind flow reversal from a westerly direction. The approach here in the DEIR is too simplistic and ignores the various complexities discussed above.
[End H42]

[Begin H43]
Page 4.5-76 Geysers Power Plant; The reference to the absence of combustion sources and acidic particulate does not consider the operation of the "incinerator" abatement systems and SO_2 emissions from both the abatement systems and the atmospheric

oxidation of H2S to H2SO4. A less than significant impact from FTP would be expected due to the proximity and elevation distances between the source(s) and receptors rather than the absence of combustion sources.
[End H43]

[Begin H44]
Page 4.8-2 (Paragraph 1) Economic curtailment is a significant concern if it results in untreated steam releases such as would occur if the production wells were required to be placed on bleed flows or the wells were damaged due to excessive thermal stress (thus requiring extensive maintenance and maintenance related emissions). This is an important point and should be in body of the text and not a footnote.
[End H44]

[Begin H45]
(Paragraph 2) Many of the Geysers Power Plant units have reached or are approaching their 25 year design lifetime. It is expected that the inefficient older units will be abandoned and the remaining marginally efficient units reconstructed to make efficient use of the lower pressure steam resource. We believe it is important to efficiently utilize this valuable, renewable and more environmentally sound resource through careful management and in so doing preserve the air quality. This should be accomplished by efficiency improvements and operating the plants at flow rates that are sustainable and protective of the steam production facilities (some form of sustainable base loading).
[End H45]

[Begin H46]
Page 4.8-1 Impacts and Mitigation Measures; No mitigation measures are proposed and the DEIR represents that none are required despite obvious adverse and significant impacts should the power plants be operated inefficiently or without regard to protecting the steam supplies. This section needs additional review and mitigation to assure that power plant operations remain consistent with good management practices which are protective of this valuable resource. We suggest appropriate “must run” agreements and regulatory support to assure that this power resource is preserved.
[End H46]

[Begin H47]
Page 4.9-12 Hazardous Materials and Waste (Paragraph 2) Mercury and arsenic are two important additional hazardous constituents of the geothermal steam which are concentrated in the power generation cycle at various locations. PG&E constructed and operates “hygiene facilities” at each of the Geysers power plants primarily in response to concerns regarding exposures to these two materials.
[End H47]

[Begin H48]
Page 4.9-19 - 4.9-20 Hazardous Materials; Add hydrogen sulfide, arsenic, mercury and possibly radon as hazardous components of geothermal steam which are found in

significant concentrations at the Geysers power plants. It should be noted that concentrations of asbestos >1% is associated with serpentine rock and soils which are common to the Geysers area and possibly on properties considered for divestiture. The District believes that Unit #16 is located on or adjacent to property extensively mined for mercury.
[End H48]

[Begin H49]
Page 4.12-11 North Geysers Unit Loading Instructions; Current and planned future modifications to system loading requirements and transmission line improvements should consider promoting the optimal use of the steam resource and electrical generation from the Geysers, especially as it relates to a sustainable base loading of units and transmission line reliability.
[End H49]

[Begin H50]
Page 4.12-14 Sanitary /Storm Sewers; Although this may or may not be the location in the DEIR to discuss this issue, it should be emphasized that the operations of Regional Wastewater Plants in Lake County are tied to the operations of the Geysers via the Geysers Wastewater Pipeline Project. Operational changes at the power plants should consider not only impacts to the steam suppliers but also the Lake County Sanitation District and the general economy of the county relative to the economic continuance of these essential services.
[End H50]

[Begin H51]
Page 4.12-15 Solid Waste; The Clearlake Landfill is a public County of Lake Solid Waste facility located in the City of Clearlake. Geothermal wastes were previously transported to the IT Benson Ridge site (a now closed facility) and also to GII site located on Butts Canyon Rd., Middletown. The GII site received PG&E wastes and is in the process of sorting out the responsibilities for remediation costs. The Geysers continue to produce both solid and liquid industrial wastes (both hazardous and non-hazardous). Those materials, amounts and locations should be identified either in this section or in Section 4.9.
[End H51]

[Begin H52]
Page 4.12-17 Electricity (Paragraph 1) The ISO coordination and dispatch to maintain reliability of the transmission system presumably will minimize line outages which have recently occurred. It should be noted that the PG&E Geysers plants do not generally have the ability to produce "in house load" power for critical component operation during line outages, but must rely on external line power for pumps, fans and controls necessary to rapidly return to production after a line fault is cleared. Air emissions during extended start up conditions have been/can be significant.
[End H52]

[Begin H53]
Section 5.3.2 Cumulative Effects by Environmental Topic.
See comments above in reference to Section 4.5, Air Quality.
[End H53]

[Begin H54]
Page 5-33 Noise - Geysers Power Plant; Steam Stacking occurs through the "stacking mufflers" located at each power plant. This operation is not normally a significant noise source. Power plant operations which result in unmuffled steam releases, produce harmonic or tonal sound because of improperly sized valves, loudspeaker annunciator use at inappropriate hours, or off-hours maintenance operations (bearing failures, construction/repair operations and truck traffic) have all been sources of noise complaints. These may be considered less than significant with new owners complying with the Lake County Planning Department Use Permit conditions for noise mitigation and adherence to the noise mitigation plans
[End H54]

[Begin H55]
Page 6-23, Section 6.4.3 Alternative Three, (paragraph 2, sentence 3) "namely steam stacking" add: well bleeds and steam field maintenance problems. References to "stacking" should be expanded to include all atmospheric releases of untreated steam. Steam stacking presently is a relatively rare event which occurs as result of sudden steam flow rejection and has been of limited occurrence due to lower pipeline pressures and the ability to intertie multiple power plants together. Stacking now is largely avoided by using the interties, the ability of the pipelines to reduce the rate of pressure increase through well steam flow reductions using automated controls.
[End H55]

[Begin H56]
Paragraph 4: While the steam field operators have a contract to accept effluent for 25-30 years, the steam supply contracts are likely not of similar duration. The remaining useful life span of many of the power plants will expire prior to this time frame unless there are provisions for maintenance, re-construction or replacement.
[End H56]

[Begin H57]
Paragraph 6 (RE: CPUC authority to force sale to particular buyers): While the DEIR explores the potential impacts of a sale to the steam suppliers, it does not explore CPUC or other agency alternatives to assure that the geothermal resource and power production is beneficially operated. The DEIR should explore the impact of classifying the Geysers Power Plant as a "stranded asset" as well as additional details regarding the viability of promoting or subsidizing "green power".
[End H57]

[Begin H58]
Attachment C, Page C-1, 1.1 Level of Operation. While the price of steam is a factor in the higher availability of the Lake County power plants, it should also be noted that these Units are of a more advanced design than most of the other PG&E Geysers plants, the steam has significantly lower H2S and corrosive content and the steam supplier has expended considerable capital to maintain production capabilities and improve steam production and electrical generation efficiencies.
[End H58]

[Begin H59]
Page C-7 (Paragraph 1); Steam is supplied by the geothermal wells utilizing the underground reservoir pressure and is not “pumped”. “Transport” would be a more appropriate term.
[End H59]

[Begin H60]
Page C-8 Remedial Actions to Maintain Steam Supplies; Load cycling increases maintenance costs and necessity to re-drill or perform additional well construction. These activities all have increased emissions or increase the potential for emissions and should be minimized to the extent practical and feasible. This should be addressed and mitigation proposed.
[End H60

[Begin H61]
Page C-10 Historic and Forecasted Generation, Table C-1. Insight as to why PG&E’s actual generation is significantly lower than available generation since 1995 may be helpful in determining how fuel pricing and contracts affect power plant operations.
[End H61]

[Begin H62]
Page C-11, Section 1.4.1, Must Run Designations. Should be modified for the Geysers power plant to favor the efficient use of the resource and to minimize air quality impacts. This unique resource should be removed from the “competitive market” if necessary for preservation.
[End H62]

[Begin H63]
Page C-24, Choices Facing Single Power Plant Operator. Page 25 describes the probable certainty of a single plant operator shutting down operations during periods of abundant hydro power, low energy demands and low pricing. This discussion appears to address combustion units and not geothermal, however a complete shut down of the geothermal plant may have unacceptable consequences to the steam field and air quality. A alternate scenario of hydro curtailment is a low load cycling operation which increases stress on components and has higher associated maintenance costs and potential air quality impacts due to breakdown emissions. Power plant cycling from a shut down situation is a less

efficient use of the resource and has a much higher excess emissions potential due to equipment failures (unit trips) during plant start up operations. This type of operation should be discouraged and regulated to the extent feasible. This should be discussed and mitigation proposed.
[End H63]

[Begin H64]
Page C-29, Spares and Maintenance Policies. This discussion outlines the negative impact on maintenance and spares availability due to price structuring of deregulation. Deferred maintenance and equipment failure is represented as having an increased profit incentive to the portfolio holder of a number of various types of power plant facilities. Equipment failures, start ups and shut downs all typically have associated excess air emissions. For geothermal plants, the emissions can be significant and unscheduled outages also can have severe consequences on the steam suppliers equipment and the geothermal reservoir. These should be discussed with mitigation recommendations.
[End H64]

[Begin H65]
Page C-33, Section 3.2.4 Geothermal Steam Supply Contracts. The steam supply contracts have historically impacted air emissions due to a variety of reasons. Where contracts were tied to electrical production there was little incentive for the efficient utilization of steam resources, often to the detriment of air quality where there is no other purchaser available for the steam and the steam flow cannot be fully curtailed because of the potential for well damage. It would appear to be in the best public interest to manage the steam resource for the most efficient utilization of this unique, environmentally superior commodity.
[End H65]

[Begin H66]
Page C-34, Section 3.3 The Influence of Must-Run Status on Operations. In order to minimize air emissions associated with cycling, excessive startups or shutdowns and consequent impacts on the steam fields causing well bleeds and/or maintenance related breakdowns, the Geysers Power Plants should be required to maintain a minimum sustaining level of availability and operation. This may be accomplished under a specific must run agreement or other similar regulatory requirement crafted to address these issues. We believe that this type of agreement or approach should be included in the mitigation required for this project. The issue would not be startup costs as much as the cost to the steam supplier and environment of having to shut down. This is missed and needs to be assessed.
[End H66]

[Begin H67]
Page 36, (Paragraph 1, footnote 71). Under CPUC D.97-04-042 would the new owner of the older Geysers units have the ability to retire the units, recover associated stranded assets and re-power or construct new replacement units?
[End H67]

[Begin H68]
Page D-5, NOP, Environmental Effects. (Bottom of page, paraphrased) The sale of the Geysers Plant could have an effect on the environment, which might be significant, if the sale causes changes such as: the amount or pattern of generation; maintenance practices; etc. (among others). The DEIR concludes that the pattern of generation and maintenance practices may change. The analysis included scenarios which considered a operating capacity range of -9% to +16% from the a 1999 baseline. The air emissions evaluation described more variation with up to a 40% increase, however the analysis did not include emissions from the steam wells or steam field maintenance associated with changes in plant operations. The cumulative impact is believed significant, given that a malfunction at a single plant is capable of causing an exceed of the AAQS and although none is offered, mitigation should be required.
[End H68]

[Begin H69]
Page G-5, Footnote 10. The model heat rate utilized 10,000 Btu/kWh instead of the more technically correct 22,000 Btu/kWh. The footnote stated that this did not affect the total potential generation nor economic dispatch position of individual plants. The reference is in the context of emissions and we fail to understand how a factor of 2.2 is essentially the same value unless the notations in the footnote are incorrect.
[End H69]

[Begin H70]
Page G-7, 2.3 Analytical Maximum Generation, 2.3.1 Procedures, (last paragraph). Typo: Geysers geothermal plants (nos. 13 and 16) supplied by Calpine wells; not Calpine wells (Nos. 13 and 16).
[End H70]

[Begin H71]
Tables G-1 through G-17; Apparent program or program input error for geothermal units. Power plants #13 and #16 are shown with identical capacities, similar generation and capacity factors and share a similar steam resource yet the H2S emissions of Unit #13 is approximately a factor of (6) higher. The H2S values reported in Table G-1 are 28 tons per year and 5 tons per year for Units #13 and #16 respectively. H2S emissions are limited by permit at Unit #13 to 9.47 lb/hr and at Unit #16 to 5 lb/hr. Actual emissions as tested at either unit are similar and typically less than 2 lb/hr (approx. 1.5 - 4 tons per year for each unit), see Exhibit A. The Title V applications (referenced as the source of input data) cite annual emissions at Unit #13 as 14.4 tpy and Unit #16 at 6.2 tpy (total 20.6 tpy). Table 4.5-27 lists 38 tpy for existing and 33 tpy as the 1999 baseline (Table G-1 total for both units is listed as 31 tpy). We also note that the ROG emissions factor (0.01#/Mwh) is the same for all units, however the NC gas concentration (source of ROG) is highly variable on a unit by unit basis. The Appendix G Tables are unclear as to the basis for the underlying emission factors and should be clearly identified.
[End H71]

Note: Included with this comment was one page of Exhibit A. Since these cannot be reasonably duplicated here on this web page they are not available electronically. Should the viewer require a copy of these, please contact Webmaster for a printed copy.

H. LAKE COUNTY AIR QUALITY MANAGEMENT DISTRICT

H1 Section 4.5 of the DEIR addresses air quality impacts of the Geysers Power Plant. The DEIR indicates on page 4.5-19 that Lake County is the only county in the state designated "attainment" for all state and federal air quality standards and state visibility standards. In response to the comment, the following sentence is added to the DEIR as the last sentence of the second paragraph on page 4.5-45:

> Adverse air quality impacts in Lake County are recognized to be largely a result of the operations of the Geysers plant, and when the plants are not operating, the associated steam fields in Sonoma and Lake County.

H2 The CPUC is aware of the differences in age and technology among the Geysers units, and that the Sonoma County units are generally older and less technologically advanced than the Lake County units, though a few Sonoma County units are as advanced as the Lake County units. Those differences were fully accounted for in the DEIR analysis.

H3 It is true that air pollutant emissions at the Geysers come from a variety of sources, not just the controlled releases of unabated steam during steam stacking events. All possible emissions sources were considered in the DEIR analysis. Some of the data and conclusions of the DEIR were drawn from the results of the Geysers Air Monitoring Program (GAMP), which detects and measures actual emissions, regardless of the source or the factors that cause increases in emissions. The GAMP was in operation during the types of events the commenter refers to, so emissions from all sources during those events were detected and measured. It is this data that was used to reach the conclusions noted in the Impacts sections of Section 4.5 of the DEIR. Regardless, as detailed in the response to Comment H15, generation at the Geysers is likely to increase rather than decrease in the future, and any potential impact caused by generation curtailment at the Geysers will be the result of restructuring, and not divestiture.

H4 While the "must-run" contracts (Reliability Must Run Agreements, or RMRAs) will require that certain Geysers units will run during certain times, these do not provide a guarantee against curtailments because of low market prices caused by hydropower spill conditions or other economic factors. In fact, under the current contracts between PG&E and its steam suppliers, such economic curtailment is allowed.

In 1997, PG&E curtailed 19.8 percent of available steam deliveries from U-N-T, and 2.8 percent from Calpine, largely because of economic considerations. That the Geysers units run at relatively high availability factors (usually in excess of 60 percent since 1994, when such curtailment was first allowed) is a testament to the low costs for producing such power. The Calpine contract is particularly advantageous to PG&E, and this is reflected in the higher economic output levels from Units 13 and 16.

The new owners would likely have the same or similar contracts that place the Geysers units at an economic advantage compared to natural gas-fired units, which typically establish the market-clearing price in 70 percent to 90 percent of the hours. Also, as detailed in the response to Comment H15, the new owner will apparently have access to programs that offer financial incentives or give some preference for generation from renewable resources, and be eligible for tax incentives that PG&E is not eligible for, which should act to increase generation at the Geysers. In any event, potential impacts caused by economic curtailments are the result of restructuring, and would occur even if PG&E would continue to own the Geysers generating units.

H5 Please see response to Comment H4. The steam prices at the Geysers under both the U-N-T and Calpine steam supply contracts typically translate to bulk power prices that are below the market-clearing prices during most hours of the year. In other words, economic incentives already exist to encourage continued substantial generation at the Geysers. Under the restructured market, Geysers generation is rejected only when its bid price is above the market-clearing price. While this price likely will fall during hydro spill conditions, perhaps even to zero, there is no direct link between hydro conditions and Geysers generation.

PG&E is now in a dispute with U-N-T as to what is the minimum generation requirement for those units (see page C-8). If the Geysers units were not divested, this dispute would continue. Thus, the controversy over sustaining a minimum generation level to avoid significant steam venting at the Geysers is a result of restructuring and a contract dispute among the existing stakeholders, and not a result of divestiture. However, because the new owner is expected to maintain substantial operations at the Geysers generating units, as noted in the response to Comments H13 and H14 below, no increase in steam venting is expected at the Geysers after the sale to a new owner.

H6 Please see response to Comment H15 for a discussion of the incentives and programs available to new owners of the Geysers units and of the use of AB 1890 funds to stabilize the price of renewable energy.

The low market prices during off-peak hours in April through May of 1998 most likely reflected unusually abundant hydropower caused by the El Niño weather conditions of 1997-98. During that time, the abundance of hydropower, coupled with the low demand during the mild spring weather, resulted in a very low market clearing price at the Power Exchange (PX) compared to the rest of the year. This is a result of simple "supply and demand" economics. However, 1997-98 was a particularly wet season in California, and such an abundance of hydropower is not likely to occur often. Therefore, because of the transmission constraints and the economic incentives detailed in the response to Comment H15, the price of power from the Geysers units is likely to be at or under the market clearing price at the PX during the vast majority of the hours of the year, thus ensuring the Geysers will continue to generate substantial amounts of energy.

The commenter's final question in this comment reads: "How significant is the loss of resources of PG&E whom still has a virtual monopoly on customers and extensive hydropower?" Under restructuring, either PG&E or a new owner of the Geysers generating units must recover their investment solely through revenues from direct sales from the units, whether to the PX or through the Direct Access market. PG&E can no longer cross-subsidize operations at the Geysers with revenues from hydropower generation or transmission and distribution operations. Therefore, either PG&E or a new owner of the units would face the same challenge of managing the units such that their operations remain economically viable on a stand-alone basis.

H7 Please see response to Comment H5. The scenario described by the commenter could occur whether or not PG&E continues to own the Geysers generating units, so the project examined in this EIR – the sale of four PG&E power plants – would have no effect on the likelihood of such a scenario occurring. The potential for all scenarios that would result in steam stacking already exists today under restructuring and would not be affected or exacerbated by divestiture. The environmentally superior alternative set forth in the DEIR (page 6-28) to sell the plants to the respective steam suppliers directly addresses this issue. The following numerical responses correspond to the commenter's suggested mitigation measures and is provided for informational purposes only since none of these proposed measures relate to environmental impacts associated with the project analyzed in this EIR.

1) The reservation of 50 to 110 MW of must-run requirements for the Geysers is beyond the authority of the CPUC, and would be a matter for consideration by the Independent System Operator (ISO).

2) Requiring that the new owners sell a prescribed amount of power into the direct access market in order to satisfy a need for minimum generation at all times would be extremely difficult in a practical sense because of the nature of energy use by most customers (which varies widely during the week) and because of the transmission constraints in the region. However, whoever owns the Geysers units will be required to take a certain amount of steam each month from the steam suppliers. This requirement effectively ensures a certain amount of generation will occur during much of the month, though not for every hour of the month; and it would effectively accomplish the same objective as requiring the new owner to find one or more direct access customers to take energy at all times.

3) As mentioned in response to H6, hydro curtailment no longer exists as a defined condition pertaining to the performance of power sales contracts. All hydro conditions are now reflected in the market-clearing prices set by the PX. In other words, during hydro spill conditions, hydroelectric plant owners will bid into the Power Exchange at very low prices, since the power produced is essentially free. That would force the PX to essentially take all the hydropower available. Curtailment at the Geysers during hydro spill conditions would only occur when owners of the Geysers units do not meet or beat the market clearing price.

4) As mentioned in the response to H15, the California Energy Commission (CEC) administers funds to subsidize eligible renewable power operations. In addition, numerous power marketers are already selling "green power" to consumers at rates 1 to 2 cents per kWh above standard market prices, following the tenet that many

> California consumers are willing to pay a premium for non-polluting, renewable energy.

H8 The commenter is referring to Impact 4.5-1 on page S-30 of the DEIR. Impact 4.5-1 is further discussed on pages 4.5-51 to 4.5-61. As described in the “Conclusions” paragraph on page 4.5-61 of the DEIR, the emissions increases are from “direct” sources which are covered by air permits. Since the emissions increases that are discussed by the commenter would occur under air permits and would be consistent with all emissions limitations and standards, they are not considered to be significant. These emissions would only be significant if they were expected to result in any significant increase in local concentrations of criteria air pollutants (see Impact 4.5-2), a significant increase in health risks in the vicinities of the plants (see Impact 4.5-3), or significant increases relative to emissions projections used in regional air quality plants (see Impact 4.5-5). None of these other impacts were found to be significant at the Geysers plant.

The reference to single or several individual events is referring to steam venting episodes that could release large quantities of unabated steam. As indicated in response to Comment H5, divestiture is not expected to increase steam venting at the Geysers plant.

With the transfer of existing permits to a new owner, plants would continue to operate under reissued air permits that would be consistent with all emissions limitations and standards. These emissions limitations and standards are assumed to be sensitive to the preservation of air quality.

H9 Regarding increased emissions, please see response to Comment H8. As the commenter notes, a 40 percent increase in emissions is not likely unless the abatement systems were changed. The analysis presented in the DEIR (page 4.5-75) indicates that the project would not have a significant impact on either local health risks or nuisance odors, and therefore mitigation is not needed. A change of abatement systems is not part of the proposed project, and is not anticipated. With respect to mercury scrubbers, please see response to Comment H11.

H10 Regarding the resources of the new owner(s), PG&E requires that successful bidder(s) for the Geysers units have sufficient financial resources and technical expertise to properly operate and maintain the plant, and the CPUC is also responsible for ensuring that the new owners are financially responsible and viable entities to operate the plant.

The commenter is correct that participation specifically in the GAMP program is voluntary. However, as the DEIR states (page 4.5-45), air permits from both the Lake County Air Quality Management District and the Northern Sonoma County Air Pollution Control District require participation in an air monitoring program comparable to GAMP. According to the Northern Sonoma County Air Pollution Control Officer (Erdman, 1998, as cited in DEIR page 4.5-83), the mechanics of assigning PG&E’s participation in GAMP to a new owner, or owners in the event different units are sold to different parties, have been worked out. PG&E recently contractually committed itself to participating in GAMP for at least the next 4 years. Even though any new owner would have to participate in an air monitoring program and the DEIR indicates that emissions from the Geysers units would not result in significant environmental impacts, in light of the commenter's preference, the DEIR on page 4.5-61 is amended to add the following mitigation measure:

Mitigation Measure Identified in this Report

~~**None required.**~~

Mitigation Measure 4.5-1: The new owner of any generating unit at PG&E's Geysers Power Plant shall participate in the existing Geysers Air Monitoring Program through at least June 30, 2002.

Monitoring Action:	The purchaser(s) of the Lake County units and the Sonoma County units shall submit documentation to the CPUC that the new owner has made a binding commitment to participate in the existing Geysers Air Monitoring Program through at least June 30, 2002, and has given notice of such participation to the Air Pollution Control Officer of the Lake County Air Quality Management District and/or the Northern Sonoma County Air Pollution Control District as applicable.
Responsibility:	CPUC
Timing:	At least 10 days prior to the transfer of title of the Geysers Power Plant.

H11 Regarding air quality monitoring, please see the response to Comment H10. With respect to seismic monitoring, PG&E does not do any seismic monitoring, nor does it participate in the seismic monitoring done by others. As described on page 4.3-13 of the DEIR, the Southeast Geysers Monitoring Advisory Committee was created by the Lake County Board of Supervisors. The continued existence of the committee would not be affected by the project, and neither the new owner nor the CPUC has authority over the composition of the committee.

With respect to the use of the chelate catalyst, it is noted that the economic costs of using the chelate would be similar for both PG&E and the new owner(s). Although a small portion of the chelate PG&E has used comes from boiler cleaning solution at its fossil plants, most of the chelate is purchased from non-PG&E power plants. Catalysts are used to make the processes in which they are used more efficient. Because the use of the chelate improves the efficiency of the abatement systems at the Geysers and the new owner's economic constraints and incentives to use it would be similar to PG&E's, it is assumed that the new owner(s) would continue to use it, unless a better system is developed.

Regarding the use of mercury scrubbers, as noted on page 4.9-13 of the DEIR, PG&E recently installed activated-carbon scrubbers to remove and collect the trace amounts of mercury. The scrubbing system minimizes mercury contamination in the sulfur waste, lowering overall operational costs by reducing the overall amount of hazardous waste generated. Since the mercury scrubbers are in place, and reduce overall operational costs, it is assumed, as stated in the DEIR, that the new operators would continue to use the equipment.

H12 Regarding continued participation in GAMP, please see response to Comment H10. With respect to the suggested mitigation measure that the seismic monitoring program continue, as noted in response to Comment H11, PG&E does not participate in a seismic monitoring program and does not have authority over the composition of Lake County's Southeast Geysers Monitoring Advisory Committee.

H13 The CPUC strongly supports the continued viability of the Geysers as a geothermal generating resource, which includes continued coordination of operations between the steam field owners and the generating unit owners. The CPUC will not approve any transfer of a Geysers generating unit to an entity that is not qualified to operate those units in a responsible manner. The response to Comment H14 below addresses the issue of "green power" policy.

With regards to maintenance policies, the commenter may have misread Attachment C to the DEIR. The new owners would have a greater incentive to maintain the Geysers plants than would PG&E (see page C-29 of the DEIR). The new owners will have the benefit of PG&E labor and insight for at least two years after divestiture, and they are free to continue to employ valuable PG&E employees.

Also, it appears that the market will provide a very strong incentive to the new owners of the generating units to ensure the long-term viability of the units and the steam fields that supply them. One cannot sell power, or recover investment, from a plant that does not generate.

H14 The purpose of an EIR is to provide decision-makers and the public with information concerning the environmental impacts of a proposed governmental action. The project will not alter any policies concerning green power. Thus, this EIR is not the appropriate avenue for examining policy concerning green power production in the state. Please see the response to Comment H15 for further discussion of policy issues.

H15 The discussion of market forces and available subsidies and other incentives for the Geysers plant is largely mooted by the fact that the electric transmission system in Northern California is significantly constrained during much of the year, meaning that bringing in power from outside the region to serve local loads is often difficult, if not impossible. Because of this fact, the ISO has designated the Geysers plant as a "must-run" facility, meaning that PG&E (and any future owner) receives payments from the ISO over and above any revenues received from selling the power from the facility, merely for remaining available to serve local loads. (This contractual arrangement assures that an owner of a must-run facility would not charge exorbitant prices during times when that facility is the only resource available to serve certain loads.) Barring construction of a new major power plant near the Geysers, or a significant upgrade of the transmission system (which would most likely include obtaining new rights-of-way because existing rights-of-way are already at maximum capacity), this situation is likely to continue indefinitely. And because of the lead time needed to construct a new power plant or to upgrade the transmission system, the situation will likely continue for several years. Therefore, an evaluation of subsidies, tax benefits and other incentives for renewable power in this EIR is not needed and would not enhance the analysis. However, for discussion purposes, a brief examination of market and policy issues related to renewable energy resources is provided below.

The California Legislature and the CPUC have enacted the restructuring of the electric utility industry in the state following the tenet that consumer choice is a very powerful tool in guiding the electric power market in the years to come. By expressing their desire to use renewable energy to power their homes and businesses, even if they must pay a premium above the cost of power from conventional resources, California consumers can in effect make decisions on the makeup of the future generating portfolio available in the state. This process is apparently already occurring, as some consumers have switched to service providers who guarantee that all or a significant portion of the power they market comes from renewable sources. Since restructuring was initiated in March 1998, at least 69,000 residential customers in the state have switched their service provider from their local utility to independent suppliers. According to the Center for Energy Efficiency and Renewables Technology, the majority of those customers switched to green power providers. Several businesses have also publicized their switch to renewable energy service providers as a means of attracting customers (article, "Green power luring consumers," by Associated Press reporter Martha Bellisle, in the September 28, 1998 issue of the *San Francisco Examiner*).

While only time will tell if a large, robust market for renewable energy resources will develop in California, early indications show that the market is promising, and could become much larger than it was before restructuring, largely because of the innovation and creativity in marketing brought about by restructuring. For example, Green Mountain Energy Resources, LLC, an energy service provider registered with the CPUC, has promised to construct a new wind turbine for every 4,000 new customers that sign up under one of its Green Power programs. The company to date has committed to installing two new turbines in the Palm Springs area because of the marketing commitment. It recently stated the two turbines represent "the first new renewable generation ever built in the U.S. because of electric deregulation" ("'Green energy' sales build new turbines," by George Raine, *San Francisco Examiner*, October 15, 1998). Use of this type of marketing technique is a direct result of the CPUC's restructuring effort, and shows that by bringing market forces to bear in the electric generation marketplace, companies will craft innovative and creative marketing techniques to become long-term players in the market. This is exactly what is envisioned in the sale of the Geysers geothermal plant. The CPUC believes that market forces will pressure the new owner(s) of the Geysers generating units to become similarly creative and innovative in marketing their non-polluting power to California consumers.

In addition to market forces, efforts by various agencies and non-profits are also acting to promote use of renewable resources in the state. For example, to help consumers in deciding whether and who to choose as a renewable energy service provider, AB 1890 (the California Legislature bill mandating restructuring) requires the CEC to implement a process for certifying renewable energy providers. In response, the CEC has established a program for certifying the renewable energy products offered by registered energy service providers in the state. The electric service industry, through the efforts of various associations and individuals, has also established a program, called the "Green-e Renewable Branding Program," for certifying renewable energy service products. Green-e certification is administered by the Center for Resources Solutions, a non-governmental non-profit organization. To receive the Green-e certificate or to qualify as a renewable energy service provider with the CEC, at least 50 percent of the energy offered through the product must come from qualifying renewable energy resources. Those include solar, wind, biomass, waste tire, municipal solid waste, small hydroelectric, digester and landfill gas, and all geothermal sources. As well, Senate Bill 1305 requires all energy suppliers to periodically disclose the sources of the energy resources they market, using a standard label created by the CEC. The CEC believes these labeling programs will become a powerful marketing tool for energy service providers.

The CEC itself is strongly promoting renewable energy to the state's consumers. In its educational material available on the Internet, the CEC points out that although consumers may have to pay a premium for renewable energy, that premium is just a small portion of the consumer's overall bill. The material also points out that the price of power from conventional sources does not include the cost to repair the environmental damage caused by the generation of that power, nor is the environmental benefit of renewable energy resources included in the pricing of the power they generate.

In relation to the various incentives available to renewable energy generators, many sections of the Energy Policy Act of 1992 (EPAct) address subsidies and tax incentives provided to renewable power producers. Section 1212 (e) specifies that qualified renewable energy facilities are eligible for a direct 1.5 cent/kWh energy production subsidy from the federal government for a period of 10 years. This credit will rise over time to account for inflation. However, the Geysers project does not appear to qualify for this direct subsidy under the EPAct. The subsidy applies only to projects owned by government and non-profit corporations or to private wind and closed-loop biomass projects, and any representation by a CPUC representative to the contrary was incorrect. If the Geysers plant was purchased by a government agency or government-owned corporation or non-profit organization, however, energy sales from the facility would apparently be eligible for the 1.5 cent/kWh subsidy under the Act.

The Geysers plant, like all renewable energy projects except hydroelectric facilities, is eligible for tax and other benefits under the EPAct and state law. The benefits vary depending on the nature of the new owner of the facilities. The EPAct (Public Law 102-486-Oct. 24, 1992) contains several provisions that encourage investment in renewable energy technologies by private and public entities. Under the act businesses can take a 10 percent business investment tax credit for purchases of solar and geothermal energy property under Sec. 1916, Permanent Extension of Energy Investment Credit for Solar and Geothermal Property.

Other applicable EPAct provisions include: Section 2111, Renewable Energy, and Section 1202, Demonstration and Commercial Application Projects for Renewable Energy and Energy Efficiency Technologies, which both offer funds, financial assistance and cost-sharing benefits to renewable energy generators for a variety of research and demonstration projects, including the demonstration of reliable generation from existing resources; Section 29, which grants a tax credit for producing fuel, including electricity, from a non-conventional source; Section 3001, Research, Development, Demonstration, and Commercial Application Activities; and Section 3002, Cost Sharing, which obliges the federal government to pay up to 50 percent of certain renewable energy research or demonstration projects.

In addition to the provisions of the EPAct, Section 168 of the Internal Revenue Code contains a Modified Accelerated Cost Recovery System (MACRS) by which businesses can recover investments in solar, wind, and geothermal property through depreciation deductions. The MACRS establishes a set of class lives for most property, ranging from 3 to 31.5 years, over which the property may be depreciated. The types of property covered by MACRS include equipment used to produce, distribute or use energy derived from a geothermal deposit, up to the electrical transmission stage.

Other potentially applicable federal laws giving preference, tax or other benefits to renewable energy generators include the Public Utilities Regulatory Policy Act (PURPA) of 1978, the Renewable Energy and Energy Efficiency Technology Competitiveness Act of 1989, the Energy Policy and Conservation Act, the Powerplant and Industrial Fuel Use Act of 1978, and the Stevenson-Wydler Technology Innovation Act of 1980.

At the state level, renewable energy policy has somewhat shifted away from using set-asides and other government mandates to ensure renewable resources were developed to help meet California's electricity needs. Instead, in the new competitive electricity market, consumers will decide whether further development of renewable resources will continue. However, many state programs offering incentives for renewable energy generators still exist. Primary among those is a program run by the CEC under which consumers of renewable energy can receive a credit of up to 1.5 cents/kWh. Some electric service providers may reflect the value of this credit in their pricing scheme, while others may use the credit to give customers a monthly bonus.

To qualify for the program, the electric service provider must: register with the CEC as a renewable electricity product provider (having a Green-e certificate does not necessarily make a provider eligible for the credit because that program has slightly different criteria for determining eligibility); serve customers previously served by either PG&E, Southern California Edison or San Diego Gas & Electric; and, obtain the renewable energy from non-utility generators within the state. Power sold by the new owner of the Geysers to customers of PG&E, Edison and SDG&E would qualify for this credit. The credit is funded through a $0.0002/kWh surcharge an all electricity sold in the state (typically, about $8 million per year), which can and will be used for other programs that promote development of renewable resources.

Conversely, if PG&E would continue to own the Geysers, purchasers of power from the Geysers would not be eligible for this credit. Thus, through the divestiture project, the Geysers should become more competitive under a new owner. And if the Geysers plant was purchased by a government-owned entity, it apparently would be eligible for a total of at least 3 cents/kWh in generation subsidies or credits.

Other California incentives programs potentially available to a new owner of the Geysers include: the Geothermal Resources Development Account (GRDA); the Energy Technologies Advancement Program; the Geothermal Grant & Loan Program; Opportunity Technology Commercialization Program; and the Energy Technology Export Program. Most of those programs offer grant and/or loans for geothermal research, resource development, commercialization, planning and impact mitigation. The GRDA, however, is specifically aimed at finding ways to make existing geothermal generators, including the Geysers, more competitive in the restructured electric industry.

By mandating these programs in state law, including the 1.5 cent/kWh credit and the certification process, the California Legislature made clear it wants the renewable energy industry in the state to continue to flourish. Some municipal utilities, especially the Sacramento Municipal Utilities District, are also offering their customers the choice of having all or a portion of their power come from renewable sources, and are crafting ways to provide incentives to make that choice.

In any event, however, PG&E has successfully generated very large amounts of electrical energy from the Geysers plant over the years without the benefit of many of the subsidies and tax benefits available to other renewable project owners. The new owner(s) of the Geysers units will likely receive the same or better subsidies or tax benefits as PG&E has had. Therefore, given the constraint of the transmission system, and PG&E's successful track record to date, any analysis of how market forces or government-mandated incentives for renewable power production will affect the viability of the Geysers would not change the conclusions of this EIR.

H16 Please see responses to Comments H14 and H15 above.

H17 Please see responses to Comments H14, H15, and J8.

H18 The term "Analytical Maximum scenario" used on the pages cited by the commenter is more relevant to the potential change in operations at the fossil-fueled plants proposed for divestiture than to future Geysers operations. Because of the potential adverse air quality impacts and damage to the steam fields, the theoretical "worst case" for the Geysers units is reduced generation. The capacity factors for Geysers units listed in the tables cited by the commenter represent the minimum expected output level under new ownership with no mitigation measures or minimum generation requirements beyond those already in place. (Please see response to Comment H7 on the appropriateness of mitigation measures.) The Analytical Maximum scenarios are not meant to capture realistic operations, but rather are artificial constructs used to analyze the maximum potential environmental impacts associated with the change of ownership for all the divested plants. The reduced capacity factors listed for the Geysers generating units in fact do not reflect any changes in behavior by the new owners of the Geysers units compared to PG&E; rather it reflects how increased generation at the other divested fossil-fueled plants depresses generation at the Geysers. In other words, under the Analytical Maximum scenario, generation from the Geysers units would fall even if they were still owned by PG&E. Thus, the change in capacity factors for the Geysers units is not a result of analyzing the effects of the divestiture of the Geysers units, but rather is an effect related to the predicted change in operations of the fossil-fueled plants at Pittsburg, Contra Costa, and Potrero after divestiture. As the DEIR states on page 4.5-55, the Analytical Maximum scenario is "extremely unlikely" to reflect a true operating scenario. The Analytical Maximum scenarios were used to provide a "conservative" analysis, as noted in the comment.

H19 To reflect the commenter's clarification, the last sentence of fourth paragraph on page 2-26 of the DEIR is revised as follows:

> ~~Mining is for aggregate and gold and used to include mercury mining.~~ Mining was an important historical use, but in the past 40 years has been confined to limited aggregate mining associated with geothermal development and otherwise to recreational prospects.

H20 To reflect the commenter's clarification, the second sentence of the fourth paragraph on page 2-35 of the DEIR is revised as follows:

> "The area is roughly ~~5.5~~ 10 miles long and ~~1~~ 4 miles wide and is drained by Big Sulphur Creek."

H21 This comment number was not used.

H22 This topic is addressed in "Existing Emissions," which begins on page 4.5-46, and Impact 4.5-3, which begins on page 4.5-71 of the DEIR.

Page 2-38 of the DEIR (third full paragraph) is hereby amended as follows:

> Geothermal steam contains reduced sulfur compounds that exist in both a liquid and gas phase. More specifically, ~~T~~the geothermal steam contains small amounts of "non-condensable gases," including hydrogen sulfide gas (H_2S). After passing through the steam turbine and the condenser, a portion of the hydrogen sulfide remains dissolved in the liquid condensate and is subsequently chemically treated to maintain solubility and prevent "air stripping" in the cooling tower. Air stripping in this case refers to the process in which hydrogen sulfide is converted from its liquid phase to a gas phase. The~~se~~ non-condensable gases are removed from the condenser and transferred to an H_2S abatement system, where they are treated to convert the hydrogen sulfide component of the gas into elemental sulfur or sulfur dioxide (SO_2) using a Stretford or Incinerator Abatement System, respectively. The chemical solution in a Stretford Abatement System oxidizes the hydrogen sulfide into elemental sulfur by producing a "sulfur cake or slurry" product that remains suspended in the cooling water and can easily be removed. Sulfur dioxide, a byproduct of hydrogen sulfide combustion in an Incinerator Abatement System, is removed using a scrubber system in which the remaining scrubber solution is re-injected into the cooling tower. After converting the H_2S component of the gas into other sulfur by-products ~~(e.g., elemental or molten sulfur)~~, the remaining non-condensable gases are routed into the cooling tower and exit to the atmosphere. Table 2.2 describes the four types of abatement systems used at the Geysers Power Plant and identifies the units to which these systems apply. As shown in Table 2.2, each of the units at the power plant has more than one H_2S abatement system available for use. Figures 2.18 and 2.19 show a schematic flow diagram of the power generating process for a typical geothermal unit equipped with a Stretford Abatement System and an Incinerator System, respectively.

Figures 2.18 and 2.19 are intended to show only the general processes involved in power generation in a steam turbine generating unit. Specific details relating to any one of the processes were not included. However, to clarify where chemicals are put into the system, Figure 2.18 on page 2-40 is hereby amended to show that chemicals (i.e., Stretford Solution) are added to the process block labeled "Hydrogen Sulfide (H_2S) Abatement System." No chemicals are added during the incinerator process of an Incinerator Abatement System and, therefore, no changes have been made to Figure 2.19.

H23 Please see response to Comments H5, H7, and H18. Not all future events can be anticipated in any modeling exercise, and for this reason capacity factors for individual generating units will periodically fall outside the ranges shown in this analysis.

As to the commenter's concerns regarding maintenance done on the Geysers units, the new owners will have a greater incentive than PG&E to maintain the generating units because they must remain operational in order to recover their investments in the units. For this reason, short-term, event-driven outages and resultant emission impacts are no more likely to occur with a new owner than when PG&E owned the units. Please also see response to Comment H13.

H24 Page 4.1-1 of the DEIR (last paragraph, first sentence) is hereby amended as follows:

> The Geysers Power Plant includes a series of ~~geysers~~ generating units dispersed throughout the northeastern portion of Sonoma County...

The last sentence of the first paragraph on page 4.1-2 is amended as follows:

> Lake County's economy is primarily based on tourism; resource extraction; retirement, residential and related services; and agriculture.

H25 To reflect the commenter's clarification (here and in Comment H19), the third paragraph on page 4.1-4 of the DEIR is hereby amended as follows:

> Other uses include recreational (~~primarily~~ hunting clubs, camps, and retreats) and ~~mining (e.g., gold, mercury).~~ limited aggregate mining associated with geothermal development. The small towns of Anderson Springs, Cobb Mountain, and Whispering Pines are located adjacent to the Geysers area to the east.

H26 Page 4.2-10 of the DEIR, the second paragraph under Geysers Power Plant subheading is hereby amended as follows:

> The Geysers, which employs ~~204~~ 208 workers, are located in rural portions of Sonoma and Lake Counties. Twelve of the 14 units are located in Sonoma County~~, so the number of workers at the Geysers is compared to Sonoma County jobs.~~ and two are located in Lake County. Of the 208 employees of the Geysers, 105 live in Lake County, 87 live in Sonoma County, and the remaining 16 workers live in other nearby counties.
>
> In 2000, Sonoma County is projected to have 184,810 jobs. Employment in Sonoma County is projected to increase by 14 percent between 2000 and 2005, representing nearly 26,000 jobs. ~~The 204 jobs~~ The 87 workers living in Sonoma County and working at The Geysers constitute less than 0.1 percent of Sonoma County's jobs. Due to data limitations for Lake County, the number of employed residents of the County is used as an indicator for the number of jobs in the County. The 105 Geysers workers who live in Lake County represent less than 0.5 percent of the 21,100 employed residents (1996 employment inventory from California Department of Finance).
>
> Although it is unknown if the future owners of the Geysers units would increase or decrease the number of employees at the plant, a doubling of the existing jobs at the Geysers would represent 0.1 percent of Sonoma County jobs and about 1.0 percent of Lake County jobs. A change of this nature would not substantially affect Sonoma

County's current jobs/housing ratio of 1.26 employed resident per job. Because data on the number of jobs located in Lake County is not available, the jobs/housing ratio cannot be determined. However, because Lake County is primarily a rural county, many employed residents likely travel outside of the county for jobs, and the county probably has a jobs/housing ratio greater than 1.00. A change in the number of jobs in Lake County of 1.0 percent would not substantially affect Lake County's jobs/housing ratio. Therefore, there would be no substantial growth or large concentration of population in Sonoma or Lake Counties, and the divestiture project would have a less-than-significant impact on population growth.

H27 Page 4.3-6, paragraph 2 is hereby amended as follows:

The bedrock within the Geysers area consists of two basic groups: the Quaternary and Tertiary age volcanic rocks of the Clear Lake Volcanic Series and the Franciscan Formation of Jurassic-Cretaceous geologic age. The Clear Lake Volcanic Series rocks are of basaltic to rhyolite composition and overlie the Franciscan rocks in the Clear Lake area north of the plant. The closest outcrop of these volcanic rocks to the Plant is on Cobb Mountain. The Franciscan Formation is the predominant rock type within the area and consists of an assemblage of volcanic and sedimentary rocks which were deposited in a subsiding marine trough. Major rock types of the Franciscan Formation include graywacke, shale, ~~and~~ volcanic of basaltic composition, and masses of serpentine. These deeply imbedded rocks were subjected to regional metamorphism and intrusion by ultramafic rocks. A thin veneer of valley alluvium sediments can be found in the local drainage channels with thicker sequences found in the valleys to the east and west of the Geysers area.

Impact 4.9-3, second bulleted item on Page 4.9-20 (Asbestos), is hereby amended to add the following:

The bedrock in the Geysers area is formed of, among other rock types, serpentine, which contains asbestos. In order for asbestos particles that are contained in the serpentine rock to become a hazard, it would have to be entrained into the air and transported by the wind to off-site receptors. For this to occur the exposed rock would have to be crushed through construction activities and clearing and grading operations. The project will not require construction operations at the Geysers plant; therefore, there would be no exposure to asbestos particles as a result of divestiture.

H28 The text referred to by the commenter is concerned with the broad overview of the regional climate and meteorological setting of the project. The commenter requests that specific text be added to point out that various communities are downwind of the Sonoma County Geyser units and thus are potentially impacted by these units. The DEIR addresses this issue in Section 4.5.3 and, thus, no modification of the DEIR text is necessary.

H29 Although concentrations of hydrogen sulfide in the gas stream may reach unsafe levels, similar to those identified in the comment, these levels have not been observed in the ambient air at offsite receptors, mainly because the pollutants are diluted in the atmosphere while being transported to downwind receptors. In order to ensure that releases of hydrogen sulfide do not occur when the levels are high in the gas stream, workers routinely measure the hydrogen sulfide concentrations in the gas stream, and when the levels are higher than normal, extra checks are performed on the hydrogen sulfide control systems, such as the Stretford units, to make sure that they are properly operating. Also, the concentrations of the analytes in the sulfur removal solutions are checked to optimize the H_2S control system.

H30 The commenter is correct that footnote "d" refers to the new federal PM-2.5 standard. As presented, the table conveys that the modified federal PM-10 standard was also retained, and the table lists the current attainment status for PM-10 (i.e., for Lake County it is "unclassified"). Footnote "d" simply reminds the reader that the attainment status for the new PM-2.5 standard has yet to be developed. The federal PM-10 standard is presented (with the new PM-2.5 standard) in Table 4.5-1.

H31 Page 4.5-20 of the DEIR (first full paragraph) is hereby revised as follows:

> LCAQMD regulates emissions from geothermal power plants through its permitting authority over stationary sources. LCAQMD Rule 411 ~~Local regulations~~ limits emissions of particulate matter for each operating unit to 40 pounds per hour.~~, and hydrogen sulfide emissions are limited to 15 pounds per hour.~~ LCAQMD has general regulations limiting sulfur emissions from various sources, set at various concentration and mass emission limits. New power plants are subject to New Source Review and Best Available Control Technology (BACT). BACT is project-specific and, for the existing Lake County units, has been defined as emissions of not more than 5 pounds per hour of hydrogen sulfide per million pounds of steam used. LCAQMD's ability to issue Authorities To Construct and Permits To Operate further refines and restricts project emissions based on the New Source Review assessment of project emission impacts on the closest receptor.

H32 Page 4.5-45 of the DEIR (second paragraph, second sentence) is hereby amended to read:

> The PM-10 monitoring stations provide data that can be analyzed by X-ray Florescence (XRF) for various compounds, including arsenic, mercury, sulfur, vanadium, and others. Ambient radon concentrations are also measured at the Glenbrook and Anderson Springs sites.

H33 GAMP PM-10 data for the Anderson Springs station and for the Glenbrook station were obtained from PG&E and are added to the revised Table 4.5-19 given below. The text in the second paragraph, fourth sentence on page 4.5-45 is amended as follows:

> Table 4.5-19 also presents ozone data from Lakeport and PM-10 data from Lakeport, Anderson Springs, and Glenbrook.

TABLE 4.5-19
LAKE COUNTY AIR BASIN CRITERIA AIR POLLUTANT CONCENTRATIONS, 1992-1996

Pollutant	State Standard[c]	Monitoring Data by Year[a]				
		1992	1993	1994	1995	1996
Ozone:						
Highest 1-hr. average, ppm[b]	0.09	0.08	0.08	0.09	0.07	0.09
Number of exceedances		0	0	0	0	0
Particulate Matter (PM-10):						
Highest 24-hr. avg., $\mu g/m^3$[b] Lakeport	50	22	30	21	30	26
Exceedances/Samples[d]		0/58	0/61	0/61	0/61	0/61
Annual Geometric Mean, $\mu g/m^3$	30	11.1	9.9	10.1	9.6	9.1
Highest 24-hr. avg., $\mu g/m^3$[b] And. Spr.[e]	50	29	29	26	45	36
Exceedances/Samples[d]		0/61	0/61	0/45	0/60	0/59
Annual Geometric Mean, $\mu g/m^3$	30	10.7	9.5	11.9	12.5	10.8
Highest 24-hr. avg., $\mu g/m^3$[b] Glenbrook[e]	50	18	18	14	24	26
Exceedances/Samples[d]		0/61	0/61	0/45	0/60	0/59
Annual Geometric Mean, $\mu g/m^3$	30	5.6	95.4	6.6	5.8	5.8
Hydrogen Sulfide (H_2S):						
Highest 1-hr. average, ppm						
(Anderson Springs station)	0.03	0.01	0.01	0.01	0.01	0.01
(Glenbrook - High Valley Road station)	0.03	0.01	0.02	0.01	0.03	0.01
(Hobergs – Pine Summit station)	0.03	0.01	0.01	0.01	0.05	0.01

a Data for ozone and PM-10 are from the air quality monitoring station in Lakeport. The hydrogen sulfide data are listed with the applicable monitoring station.
b ppm = parts per million; $\mu g/m^3$ = micrograms per cubic meter.
c State standards for ozone and PM-10 are not to be exceeded; the state standard for hydrogen sulfide is not to be equaled or exceeded.
d PM-10 is usually measured every sixth day (rather than continuously like the other pollutants). For PM-10, "exceedances/samples" indicates the number of exceedances of the state standard that occurred in a given year and the total number of samples that were taken that year.
e Data from LCAQMD.

SOURCE: California Air Resources Board, *California Air Quality Data*, 1992, 1993, 1994, 1995, and 1996.

H34 Page 4.5-46 of the DEIR (last paragraph and then continuing onto the next page) is hereby revised as follows:

> Geothermal steam contains small amounts of naturally occurring non-condensable gases, including carbon dioxide, H_2S, ammonia, methane, hydrogen, nitrogen, and trace amounts of other gases, including reactive organic gases, benzene, and radon.

> Geothermal air pollutants are not generally emitted from steam wells, steam transmission lines and steam stacking facilities under normal operations. Steam is emitted during well construction, testing and maintenance operations. ~~, and non-condensable~~ Most of the geothermal emissions are from the cooling towers and gas treatment facilities at power plants. While ~~W~~well bleeds and well maintenance steam releases are currently the largest "steam field" emission sources, steam field emissions are relatively insignificant when the power generating units are operating. Most of the air pollutant emissions from the Geysers plant are due to naturally occurring constituents of the geothermal steam released to the air from the evaporation of the circulating water and "air stripping," which occurs in the cooling towers (provided the gas treatment systems are functioning properly).~~during condensation of the steam after it passes through the turbine.~~ One significant constituent is H_2S, and all the units are equipped with H_2S abatement systems.

H35 Please see response to Comment H34.

H36 Though stacking can occur with a mere slowdown in the rate of steam use at a generating unit, the commenter is correct that stacking events are more likely to occur after an immediate 100 percent rejection of steam flowing to a Geysers generating units, such as when a generating unit is tripped off-line. For further clarification, the second sentence of the first full paragraph of page 4.5-47 is hereby revised as follows:

> H_2S emissions can occur as a result of steam stacking, which is the term used to describe the controlled release of unabated steam in order to relieve a buildup of steam pressure in a geothermal field due to a temporary slowdown or cessation in use of the steam wells.

H37 As detailed in the response to Comment H18, the analytical maximum scenarios examined in the DEIR conclude that generation at the Geysers may decrease somewhat in the future, but such a scenario is an artificial construct designed to capture the maximum potential environmental from divestiture of the Geysers units. Because of the factors discussed in the response to Comment H15, incidences of shutting in the steam wells are not expected to increase under divestiture because the new owner(s) of the Geysers generating units will have significant incentives to operate the Geysers units at relatively high capacity factors. Thus, there would be no impacts expected from divestiture, even if generation decreased as described in the analytical maximum scenario. Also, the magnitude of a H_2S gas release during such an operation would be considerably lower than releases that may occur from a stacking event and would result in lower concentrations at off-site receptors, even though such a release may create less turbulence than a stacking event.

H38 Please see response to Comment T7.

H39 The DEIR's air quality analysis concerning emissions from the Geysers Power Plant fully accounts for the fact that wind patterns in the Geysers area generally result in all emissions from both the Sonoma County and Lake County Geysers generating units flowing into the

Lake County air basin. As detailed in the response to Comment H3, the Geysers air quality analysis relies mainly on the results of the Geysers Air Monitoring Program (GAMP), which detects existing emissions, regardless of their origin or destination. However, for further clarification, Page 4.5-47 of the DEIR (last paragraph and then continuing onto the next page) is hereby revised as follows:

> Table 4.5-21 shows criteria air pollutant emissions from the plant units located in Lake County for 1995, 1996, and 1997 and compares the 1997 estimates with county-wide emissions for Lake County in that year. Table 4.5-22 shows the 1995, 1996, and 1997 criteria pollutant emissions from the Sonoma County units and compares 1997 emissions ~~the values~~ with county-wide and basin-wide emissions for Sonoma County. As indicated in Table 4.5-22, the Geysers Power Plant accounted for relatively large portions of Sonoma County's 1997 inventory of PM-10. Given that prevailing winds tend to transport emissions from the Sonoma County units to the Lake County Air Basin, a comparison of the aggregate emissions from all of the Geysers Power Plant units with Lake County emissions is also appropriate. Table 4.5-22a provides such a comparison and shows that Geysers Power Plant emissions constitute a substantial fraction of total Lake County emissions of total organic gases and PM-10.

TABLE 4.5-22a
EMISSIONS FROM GEYSERS POWER PLANT UNITS, 1995, 1996, 1997

	Emissions (tons per year)[a]			1997 Emissions As
Pollutant	**1995**	**1996**	**1997**	**Percent of Lake County**
Total Organic Gases	2,463	2,839	2,755	46
Reactive Organic Gases	29	33	32	0.8
Particulate Matter (PM-10)	552	651	734	16

a Emissions estimates represent the sum of emissions estimates shown in Tables 4.5-21 (Lake County units) and 4.5-22 (Sonoma County units).

H40 The risk assessments that are in the DEIR reflect the latest reference dose information officially released by the Office of Environmental Health and Hazards Assessment (OEHHA). These reference doses are revised when new data are reported by the scientific community. For plants that emit pollutants with revised reference doses, the risks must be recalculated. Under AB 2588, the Air Toxics "Hot Spots" Information Act, all industrial facilities in the state must report any changes in emissions and/or any changes in risks from their plants on a biennial basis. Thus, if reference doses are revised, the owner(s) of the Geysers units would be required to update their risk assessments in accordance with AB 2588.

H41 The emission estimates reported in the air quality section (as well as the baseline and analytical maximum capacity factors used to derive them) are consistent with those reported in other parts of the EIR. With regard to the comment on emissions factors, the emissions reported in Tables 4.5-27 and 28 are based on factors that were derived from measurements for these systems and are not based on permitted levels. Actual production rates were used in combination with the emission factors to estimate the emissions reported in the tables. Please see the responses to Comments H8 and H9 for further discussion of the analytical maximum scenarios and air quality impacts.

H42 The DEIR refers to steam stacking as an example of a condition that can result in unabated releases. In order to include other factors besides steam stacking that can result in these releases, the text on page 4.5-75 (under "Geysers Power Plant") is hereby amended to read as follows:

> The principal health risk that could be experienced from plant operations under the 1999 A-Max scenario would be the potential for increased acute exposure to toxic hydrogen sulfide emissions. For the Lake County units, emissions of hydrogen sulfide are estimated to remain the same (see Table 4.5-27) under the 1999 A-Max scenario as compared with the 1999 Baseline, while the corresponding emissions at the Sonoma County units under this scenario are estimated to increase by approximately 40 percent (see Table 4.5-28). The scenario analyzed in Tables 4.5-27 and 4.5-28 is the one that maximizes "controlled emissions" and not the scenario that depicts the minimum level of operations that has generally been used for the A-Max for the Geysers (see Table 3.1). Although steam stacking has been shown to cause exceedances of ambient air quality standards (AAQS), the same can be demonstrated for emissions from untreated well bleeds, normal and abnormal power plant operations. Steady state "controlled" emissions are capable of, and have been the source of both nuisance complaint generation (odors) and AAQS exceedances. These events are typically associated with episodes of regional air stagnation and a "flushing" of built up pollutant concentrations from the West Geysers area into Lake County during the early afternoon wind flow reversal from a westerly direction. ~~However, this increase in hydrogen sulfide emissions would not be expected to result in a significant increase in health risk or nuisance odor complaints since the two phenomena are essentially independent of one another. This is because the peaks in hydrogen sulfide concentrations (and ensuing complaints) that have occurred in the past have been the result of uncontrolled releases of steam due to events like steam stacking rather than from the steady-state, "controlled" emissions released at the power plants.~~ As discussed in the setting section, in addition to H_2S abatement systems to reduce controlled operations, an automated pipe manifold system has been installed, and this system has significantly reduced the incidents of steam stacking. Because the project would not affect operation of the H2S

> abatement systems, or the manifold systems, steam wells and wellheads, or change the applicability of any air district rules or regulations, or affect the frequency of regional air stagnation, the project would not have a significant effect on the local health risks or the potential for nuisance odor complaints that are associated with controlled releases, or steam stacking and related uncontrolled releases of steam.

H43 The commenter is correct in that some of the Geysers units (5, 6, 7, 8, 11, and 12) utilize an incinerator system (a form of combustion) as an emission control system. It is also true (and is so stated on Table 2.2 of the DEIR) that emissions from this system contain SO_2. However, this abatement system is by no means comparable to the large boilers found in the Bay Area fossil-fueled plants, which release their emissions through a tall chimney via a generally hot, dry process, versus the Geysers incinerator abatement systems emissions being released through cooling towers (essentially a wet, cool process). Furthermore, one of the key features of fallout-type particulate (FTP) from the fossil-fueled plants (as described on pages 4.5-13-14 of the DEIR) is the formation of $FeSO_4$, which is a result of the interaction between the boiler exhaust gas and the boiler tube steel walls. While there are apparently similar chemical processes between the Geysers incinerator abatement systems and the fossil-fueled power plants, no data is available to suggest that FTP (as discussed beginning on page 4.5-13 of the DEIR) is emitted from the Geysers Power Plant. There are also great process differences between the two systems. Regardless, the commenter is correct that because the Geysers Power Plant location is far from any potentially impacted sources, the DEIR is correct in stating that, for the Geysers, this would be a less-than-significant impact. Thus, in response to this comment, the first sentence of the third paragraph of page 4.5-76 of the DEIR is hereby amended to read:

> Unlike the three Bay Area fossil-fueled power plants, ~~Because~~ there are no combustion sources ~~used in the process~~ that can generate acidic particles at the Geysers; therefore, no measurable impact from FTP is expected at the Geysers. Geysers units 5, 6, 7, 8, 11, and 12 do utilize an incinerator based emission control system that emits exhaust gasses with similar chemistry to that causing FTP from the fossil-fueled power plants. However, the distance of these Geysers units from potential receptors that could experience any FTP-like nuisance effects from these units is far greater than that of the Bay Area fossil-fueled power plants and thus, further ensure that no FTP-like nuisance effects would be experienced.

H44 The issue of economic curtailment is mentioned in a footnote on page 4.8-2 of the DEIR instead of in the body of the text because it is an economic issue that is not directly related to plant ownership and therefore is not affected by divestiture. Economic curtailment has occurred at least in the U-N-T fields since 1994, and would likely continue under PG&E ownership. Divestiture would have little or no detrimental effect on economic curtailment, and in fact would be more likely to reduce curtailment as shown in the response to Comments H5, H7, and H13 through H17.

H45 The number of units that could be closed to better utilize the steam resource is quite limited by the fact that geothermal steam can only be transferred to another site less than a mile away. Both PG&E and the new owners would face the same decisions on plant closures and reconstructions, so that divestiture would not change this situation. The new owners will have a strong incentive to maintain the resource in a manner that is most economically efficient and beneficial. The alternative of selling the plants to the steam suppliers only reinforces this incentive.

While the commenter believes that operating the units at a sustainable, baseload flow rate would efficiently utilize the steam resource, the Legislature and the CPUC have decided to rely on the marketplace to the extent feasible as the best means of efficiently managing these resources. The CEC is charged with assessing the societal benefits and costs of pursuing different resource options. Nevertheless, restructuring is intended to decentralize resource planning so as to avoid the compounding of mistakes that can occur with one decision-maker overseeing all.

H46 There is no basis for concluding that Geysers units would be operated inefficiently after divestiture. Please see responses to Comments H7 and H45, where related issues of energy efficiency are addressed.

H47 A new paragraph on page 4.9-12 of the DEIR (following the fourth paragraph) is hereby added as follows:

> PG&E maintains hygiene facilities (buildings with lockers, showers, and coverall storage areas) at each unit site. These facilities minimize worker exposure to the trace contaminants that are found in the steam, primarily arsenic.

The activated-carbon scrubbers that remove mercury from the geothermal steam are described in the DEIR on page 4.9-13 (second paragraph).

H48 The comment refers to the project setting, which is discussed starting on page 4.9-12 of the DEIR, and not to a project impact. Page 4.9-12 of the DEIR (fourth paragraph, second sentence) is hereby revised as follows:

> Other constituents include ammonia, hydrogen, methane, nitrogen, carbon dioxide, and trace amounts of other gases, including radon, as well as trace amounts of various metals, including arsenic and mercury. Asbestos is present in serpentine rock and soils, which are common throughout the Geysers area.

The presence of trace metals arsenic and mercury in geothermal steam was also described in the DEIR on page 4.9-13 (second paragraph). Please see the response to Comment T18 for a discussion of mercury mining in the Geysers area, as well as further details on potential asbestos contamination.

H49 The North Geysers Unit Loading Instructions are instructions written by PG&E staff to ensure that system operators preserve system reliability. They are in a state of flux because another unit, Geysers Unit 11, is being "wired" into the north Geysers system to provide greater and more reliable voltage support in the Mendocino area. These instructions and the responsibility for observing them have now been transferred to the ISO and it is assumed in the DEIR that the ISO will continue to observe them as they are modified to reflect the completion of the Unit 11 interconnection.

These instructions do not consider economic or energy policy issues and would not be an appropriate document into which to insert such considerations. Such considerations are currently in the hands of PG&E and will in the future be in the hands of the new owner of the Geysers plant. The economics of the steam supplies will certainly affect how these units are operated. It may be possible that in the context of providing green power, the Geysers could be employed in a more baseloaded mode in order to firm up other sources of green power such as wind generation or hydro. That issue is appropriately left to the discretion of the new owner.

H50 Page 2-39 of the DEIR notes that the Lake County Sanitation District (LACOSAN) has a long-term contract to supply wastewater to the Geysers Power Plant where it is injected into the steam fields. A pipeline from the Southeast Regional Wastewater Treatment Plant (SERWTP) delivers up to 8 million gallons a day of treated wastewater or lake water to the Southeast Geysers geothermal field. This mutually beneficial arrangement provides LACOSAN with a means to dispose of SERWTP wastewater effluent and allows the steam field operators to increase recoverable steam pressure and improve the reliability of steam delivery. This information was not presented in the discussion on sanitary and storm sewers because that section of the DEIR examines potential impacts of the proposed project on sanitary and storm sewer systems and, in the case of the Geysers, there would be no such impacts, nor would there be any impacts on LACOSAN. CEQA does not require consideration or discussion of economic effects, except insofar as they may result in secondary environmental effects. Given that the proposed project would not affect LACOSAN, there is no reason to assume that there would be project-generated economic effects related to the continued provision of wastewater management services in Lake County.

H51 The source points, waste composition, quantity, and ultimate disposal method of each hazardous waste stream generated at the Geysers Power Plant are summarized in the DEIR on page E-5 of Attachment E.

PG&E has provided the following information on waste generation at the Geysers Power Plant for 1998 through September:

Unit	**Hazardous Waste (Tons)**	**Nonhazardous Waste (Tons)**
7&8	39	0
9&10	41	0
13	136	135
14	141	72
16	33	145
17	442	436
18	0	171
20	28	241
Various	146	23
Common	27	0
Total (1998 through September)	**1,035**	**1,225**

Note also that the amounts of hazardous and non-hazardous wastes generated each year can vary significantly, depending on whether special equipment or site upgrades or repairs are performed.

Page 4.12-15 of the DEIR (fifth paragraph, first sentence) is hereby amended to read:

> Solid waste generated in Lake County is disposed of at the ~~privately owned~~ Eastlake ~~Clearlake Highlands~~ Landfill, located off State Route 53 in the City of Clearlake.

H52 The commenter is correct that the Geysers generating units do not have "black start" capability, meaning they must have off-site power available to start up, and that significant emissions occur during unexpected shutdowns and resultant startups. However, divestiture of the units will have no effect on the availability of off-site power, and therefore no impact on the reliability of the electric grid in California. As noted by the commenter, transmission outages are likely to decrease under restructuring due to the operation of the ISO, because its one and only task is to ensure reliability of the grid. In contrast, the previous grid operators (PG&E, Southern California Edison, and San Diego Gas & Electric) each operated only a portion of the state's transmission grid and had a variety of motivations behind their transmission system operational decisions, such as protecting their generating assets. By having a single entity controlling all of the state's transmission grid, with continued reliability as its only motivation, outage duration and frequency in the restructured electric utility industry are more likely to decrease rather than increase.

H53 Comment noted.

H54 The DEIR assumes that the Geysers units under new ownership would operate within the parameters of their existing permits, as stated on page 3-8, first paragraph. In its comment, the agency agrees that if this is the case, the noise impact would be less than significant.

H55 In response to comment, the third sentence of the second paragraph under Section 6.4.3 (page 6-23) is hereby amended to read:

> This may reduce environmental effects that are of concern, namely steam stacking, well bleeds, and field maintenance problems.

The last sentence of the same paragraph (pages 6-23 – 6-24) is hereby amended to read:

> As owners of the generating units, the steam field operators would be uniquely positioned to coordinate the operations of the units to maximize utilization of steam pressure and avoid steam stacking, well bleeds, and other problems associated with field maintenance.

H56 As noted on pages 2-4 to 2-5 of the DEIR, PG&E plans to transfer its rights and obligations under the existing steam supply contracts with U-N-T and Calpine to the new owner(s). Divestiture would not change the future need for maintenance at the units or shorten the useful life span of the units.

H57 Utility plants are not classified as "stranded assets" arbitrarily by the CPUC. Whether a plant is an "economic" or "uneconomic or stranded" asset is derived by comparing the remaining book value to the market value. The important factor is not the determination of whether an asset is economic, but rather the dollar amount representing the difference between the book and market values. That determination cannot be made until the asset is market valued in some fashion, including by an auction. No other special significance is attached to a "stranded asset." Please see responses to Comments H13, H14, and H15 for discussion of "green power" policies.

H58 The Lake County steam contract provides for prices as much as 50 percent lower than those in Sonoma County, partially because the steam from Calpine's field is less contaminated than steam from other fields, thus reducing abatement costs. This lower price is sufficient incentive to dramatically reduce economic curtailments. Calpine does drill more intensively to supply its adjacent QF plants, which hold comparatively lucrative Interim Standard Offer 4 (ISO 4) contracts with PG&E, as mentioned on page C-8 of the DEIR. Please see response to Comment H2.

H59 Please see response to Comment N61.

H60 Attachment C of the DEIR concludes that divestiture is more likely to *reduce* cycling at the Geysers, not increase it. In any event, as noted in the responses to Comments H5, H7, H13, and H44, any increase in load cycling at the Geysers, and the resultant increase in emissions, would be a direct result of restructuring, and not of divestiture of the units.

H61 The first bullet on page C-8 of the DEIR, “Baseload to load-following operation,” explains why Geysers generation has been economically curtailed and discusses how “fuel pricing and contracts affect power plant operations.”

H62 Please see response to Comment H7.

H63 Please see responses to Comments H5 and H7. Cycling of the Geysers units already occurs under PG&E ownership, and is likely to decrease, rather than increase, under any new ownership scenario.

H64 Please see response to Comment H13. The commenter may have misinterpreted the discussion at C-29 to arrive at a completely opposite conclusion from the DEIR. The portfolio holder discussed there is PG&E, not the new owners, who will have a small portfolio of plants, if any. Therefore, assuming the new owners only have one or few generating plants from which to recover their investment, they would be more likely to ensure their units are well maintained.

H65 The commenter’s statement reflects the rationale behind the designation of the environmentally superior alternative in the DEIR. As well, if the steam field owners do not exercise their right of first refusal, the new owners will assume the existing steam contracts. Therefore, the project will have no effect on any potential impact related to the steam supply contracts.

H66 Please see responses to Comments H5, H7, H15 and J8.

H67 CPUC Decision 97-04-042 applies to those electrical utilities regulated by the CPUC. The new owner of the Geysers will presumably be a non-utility company, and therefore will not be regulated by the CPUC. As a result, the policies contained in D.97-04-042 will not apply to the new owner. New owners of the divested power plants will have the freedom to retire, repower, or replace the generation units. The recovery of stranded generation assets, legislated by AB 1890, is restricted only to utility companies regulated by the CPUC.

H68 The commenter references the Notice of Preparation (NOP), which is the public notice required by CEQA stating the lead agency’s intent to prepare an environmental impact report. The NOP provides a brief discussion of the project and the known potential environmental effects that will be addressed in the EIR. It was prepared before any of the analysis conducted for this EIR was even started, and does not reflect any of the conclusions reached in the DEIR. However, addressing the commenter’s concerns about the cumulative impact of emissions from all parts of the Geysers area, including the steam fields, the analysis conducted for the air quality section (Section 4.5) of the DEIR relied heavily on the data collected by the GAMP, which detects all pollutants coming from the Geysers units, steam fields and related equipment. That data confirmed the effectiveness of the pipe manifold network system installed at the Geysers in the mid-1980s, as noted on page 4.5-47 of the DEIR. Because of this technology, the GAMP has detected only one incidence of release of significant amounts of H_2S in recent years, as noted on page 4.5-45 of the DEIR. In any event, the DEIR concludes that malfunctions at any of the Geysers units leading to exceedance of ambient air quality standards are no more likely to occur under a new owner than under PG&E's continued ownership. As well, existing air quality permits, with which the new owners of the Geysers units must comply, clearly specify that the new owner must not exceed ambient air quality standards, including H_2S concentration limits, and that they must participate in an air quality monitoring plan similar to the GAMP in order to ensure standards are not violated. Thus, with these permit requirements, the continued use of the manifold piping system and continued coordination between the steam field owners and the generating unit owners (as specified in the steam supply contracts), the DEIR concludes that the potential for the project to result in increased impacts associated with exceeding ambient air quality standards is less than significant.

H69 The footnote is correct. The geothermal purchase contracts governing payments by PG&E for geothermal generation from U-N-T and Calpine base payments on the number of kilowatt-hours produced. Thus, PG&E determines dispatch of Geysers generation based upon the incremental cost of generation, not on the amount of geothermal energy used. In the SERASYM™ modeling, the same behavior needed to be employed to forecast future Geysers operations. Because the incremental cost of generation for most utility generating units is determined by a combination of fuel cost and unit specific energy conversion efficiency, the same approach is followed in the SERASYM™ algorithms, thereby necessitating special procedures to accurately reflect the geothermal contracts. These adjustments involved normalizing the unit heat rates for each geothermal unit to a 10,000 Btu/kWh "pseudo-heat rate" so that the actual cost of geothermal steam was reflected in forecasted operations of the units. Once it was determined how much the units would run (using the above procedures), the actual heat rates were used to calculate the emissions.

H70 Page G-7 (last paragraph, first sentence) is hereby amended to read:

> The Geysers geothermal plants (Nos. 13 and 16), supplied by Calpine~~, wells (Nos. 13 and 16)~~ are already running at their steam-limited maximum levels; the remainder, supplied by UNT, are not.

H71 The source of emission rates in the SERASYM™ program for both units is the CEC Electricity Report 94 (page A-II-A-19, dated 12/8/94), wherein the column for hydrogen sulfide was understood to be 7 pounds per hour and 1.1 pounds per hour for Geysers Units 13 and 16, respectively,[7] which is within permitted levels. The reason that the emissions do not differ by the full 7 to 1.1 factor of 6.36 is that the decline in capacity caused by steam supply reduction is more severe for Geysers Unit 13 than for Geysers Unit 16.

[7] The column heading in the report is actually lb/MMBtu which would result in a much higher emission rate, but CEC staff clarified that the column should have been listed as pounds per hour.

It is noted, however, that the emissions estimates for the Geysers units in Chapter 4.5 (Air Quality) of the DEIR relied upon the information contained in Attachment G for electricity generation estimates and for hydrogen sulfide only and that Title V application data was used as the basis for ROG, NO_x, and PM-10 emissions estimates. Based on Title V application data, ROG emissions factors used for the emissions estimates included in Chapter 4.5 of the DEIR were 10.9 pounds per GWh for Unit 13 and 8.0 pounds per GWh for Unit 16, which, incidentally, round to 0.01 pound per MWh. Since the footnotes to Tables 4.5-27 and 4.5-28 are not precise on this point, those two tables are hereby revised as follows:

TABLE 4.5-27
LAKE COUNTY GEYSERS POWER PLANTS
CRITERIA AIR POLLUTANT EMISSIONS, 1999 AND 2005

	Estimated Emissions in Tons Per Year[a]			
Pollutant	**Existing[b]**	**1999 Baseline**	**1999 Analytical Maximum**	**2005 Cumulative Analytical Maximum**
Carbon Monoxide	0	0	0	0
Reactive Organic Gases	7	6	6	5
Nitrogen Oxides	0	0	0	0
Hydrogen Sulfides	38	33	33	31
Particulate Matter (PM-10)	46	39	39	38

a Baseline and analytical maximum emissions estimates were developed using generation rates developed by Sierra Energy and Risk Assessment, Inc. for this report, ~~and~~ emissions factors for carbon monoxide, ROG, NOx, and PM-10 derived from the Title V applications (to the Lake County AQMD) for Units 13 and 16, and emissions factors for hydrogen sulfide from the California Energy Commission's Electricity Report 94.

b Existing emissions reflect an average of emissions over the 1995 to 1997 period. The emissions estimates were made based on electricity generated during the 1995 to 1997 period, ~~and on~~ emissions factors for carbon monoxide, ROG, NOx, and PM-10 derived from the Title V applications (to the Lake County AQMD) for Units 13 and 16, and emissions factors for hydrogen sulfide from the California Energy Commission's Electricity Report 94.

Finally, it is noted that the hydrogen sulfide emissions data provided by the commenter substantially lowers the emissions estimates of that pollutant. Using the commenter's data, emissions of hydrogen sulfide from the two Lake County units would be 5 tons per year under existing conditions, 1999 baseline, and 1999 Analytical Maximum, and would be 4 tons per year under the 2005 Analytical Maximum. The corresponding DEIR estimates were in the 30 to 40 ton-per-year range. However, since the DEIR concluded

TABLE 4.5-28
NORTHERN SONOMA COUNTY GEYSERS POWER PLANTS
CRITERIA AIR POLLUTANT EMISSIONS, 1999 AND 2005

	Estimated Emissions in Tons Per Year[a]			
Pollutant	**Existing[b]**	**1999 Baseline**	**1999 Analytical Maximum**	**2005 Cumulative Analytical Maximum**
Carbon Monoxide	1	1	1	1
Reactive Organic Gases	25	24	30	30
Nitrogen Oxides	3	3	4	4
Hydrogen Sulfides	516	488	685	696
Particulate Matter (PM-10)	600	571	778	786

a Baseline and analytical maximum emissions estimates were developed using generation rates developed by Sierra Energy and Risk Assessment, Inc. for this report, ~~and~~ emissions factors for carbon monoxide, ROG, NOx, and PM-10 derived from the Title V applications (to the Northern Sonoma County APCD) for Units 5, 6, 7, 8, 9, 10, 11, 12, 14, 17, 18, and 20, and emissions factors for hydrogen sulfide from the California Energy Commission's Electricity Report 94.

b Existing emissions reflect an average of emissions over the 1995 to 1997 period. The emissions estimates were made based on electricity generated during the 1995 to 1997 period, ~~and on~~ emissions factors for carbon monoxide, ROG, NOx, and PM-10 derived from the Title V applications (to the Northern Sonoma County APCD) for Units 5, 6, 7, 8, 9, 10, 11, 12, 14, 17, 18, and 20, and emissions factors for hydrogen sulfide from the California Energy Commission's Electricity Report 94.

that even the higher emissions estimates included therein would not be significant, the conclusion would remain the same with respect to the lower estimates as well.

September 21, 1998

Mr. Bruce Kaneshiro
CPUC EIR Project Manager
C/O Environmental Science Associates
225 Bush Street, Suite 1700
San Francisco, CA 94104-4207

Re: Draft Environmental Impact Report comments, CPUC Application #98-01-008
Geysers Geothermal Power Plant & Other Divestitures

Dear Mr. Kaneshiro:

[Begin I1]
I wish to thank CPUS/ESA staff for past presentations before this Board and attempts to fully address issues in the above referenced matter. Nevertheless, it was disappointing that a separate EIR could not be written as requested by the Board of the Geysers sale nor an official public hearing held in our area to allow formal verbal comment on the draft EIR. It would have made participation by the public much easier.
[End I1]

[Begin I2]
I ask that the final EIR seriously consider the many and interrelated issues which were brought forward during our discussion, comments at the recently held public participation meeting of September 15, 1998, and the comments both written and verbal forwarded to you by Board of Supervisor members, the public and agency staff.
[End I2]

[Begin I3]
The Geysers play an important role in the continued prosperity of Lake County, and your conclusion that effects of 1-2% are not a significant cause of concern is not acceptable. It is the Board's feeling that if the sale of Geysers facilities results in a selling price lower than the tax base now established, Lake County and special districts will be adversely impacted. Mitigation of these impacts is quite essential. We realize that much of the DEIR scenarios are based on assumptions and forecasting, and ask that you take a more detailed and wider spectrum of scenarios and suggest specific mitigation steps should the less likely and desirable occur.
[End I3]

[Begin I4]
For the record and to ensure that the statement is included in the EIR record, I want to repeat the statement included in May 13, 1998 letter, *"It is vital to the well being of our county to preserve our air quality (the only air district in the state to meet all the ambient air quality standards), preserve our chosen waste treatment option of injecting waste water into the Geysers and recognize that the Geysers represent a significant direct and indirect component to our local economy.* ***The Geysers is a world class environmental show piece for renewable green energy***

which needs to be preserved and promoted. *It is of paramount importance that the long standing and mutual cooperative basis that has largely contributed to the success of the Geysers, as an environmental model project, be continued and viable under CPUC decisions as a result of deregulation and divestiture."*
[End I4]

[Begin I5]
We continue to request the opportunity to review, prior to the CPUC consideration of approval, the proposal and qualifications of the potential owner to assure that our needs will be protected.
[End I5]

[Begin I6]
The Board is continuing to request that any new owners continue to honor existing written agreements and that unwritten operating protocols be incorporated as a precondition of a change of ownership. Other members of our community and staff have further enlarged upon these issues as part of the EIR process. We would especially like to see recommendations on those activities that have been identified.
[End I6]

[Begin I7]
The EIR needs to examine in more detail green power policy to ensure a viable continuing industry in California and to tie that into this sale approval consideration. When appearing before the Board, ESA/CPUC staff stated federal law gave a 1.5 cent/KW subsidy to green power and the Geysers. Is this still a valid statement? AB 1890 funds apparently enabled operation during the current year's high availability to hydro-power by ensuring a temporary transition floor of 3 cents/KW. The CPUC/ESA staff and DEIR contend that it is not an issue because of desirable economics, yet during the current year PX price apparently fell to zero cents/KW (Appendix C). Will AB 1890 apply to the Geysers Plants once the plants are sold, or will they be treated as merchant plants? Will they still be able to be assisted during transition years by AB 1890? Please, identify any incentives given to green power by state policy and explain how these will be incorporated into the CPUC's consideration in utilizing the final EIR and decision on sale approval.
[End I7]

[Begin I8]
Hydro-curtailment's effect upon the steamfield management and the impact on industry's continuing ability to manage our air, water, land and economic resources continues to be of concern. We realize that the question is not fully resolved, and we further understand PG&E and steamfield operators may identify specific mutual steps to address this concern. Any such steps, such as assurances of minimum generation consistent with protection of the steamfield integrity during all time periods including high hydro availability periods of time, should be identified, and it must be made clear how they will continue with new owners that are without PG&E's resources and customers. This issue has been commented on extensively and we ask that the final EIR identify specific possible mitigation steps for all reasonable outcomes.
[End I8]

Thank you for your consideration and commitment to a fair and factual final EIR that identifies potential impacts this divestiture proposal may have on our county, state and country, and identifies mitigation that could be implemented to achieve policy goals and protect our environment.

Sincerely

/s/

Louise Talley, Chairman
Lake County Board of Supervisors

CC: CPUC Members

I. LAKE COUNTY BOARD OF SUPERVISORS (Louise Talley)

I1 The proposed project is the divestiture by PG&E of its three fossil-fueled power plants and its Geysers geothermal plant. While it would have been possible to prepare two separate EIRs (one for the sale of the fossil-fueled plants and another for the sale of the Geysers units), CEQA does not require that PG&E's application be so divided for purposes of environmental review. The same analytical requirements would apply, and the same information would be presented, with respect to the Geysers units, whether one or two EIRs were prepared. Indeed, the preparation of a single EIR facilitated the analysis of the manner in which the sale of the fossil-fueled plants would affect the Geysers plant, and vice versa. In any event, separate discussions on the Geysers Power Plant were provided throughout the DEIR under headings identifying them as such. Any reader specifically interested in issues pertaining to the Geysers can readily locate such information in the appropriate topical sections.

Regarding a separate public hearing in or near Lakeport, CEQA does not require a lead agency to hold a public hearing on a DEIR or at any stage of the environmental review process (CEQA Guidelines, Section 15202), but as a courtesy and convenience to the public, the CPUC elected to conduct a public hearing in San Francisco during the public review period (August 5–September 21, 1998). In accordance with the requirements of CEQA, written comments on the DEIR were accepted during this review period. The CPUC did conduct a public information workshop in Lake County on September 2, 1998. Key findings of the DEIR were presented to the public at that workshop, and CPUC staff attempted to answer the public's questions as well. Moreover, the public was encouraged to submit written comments to the CPUC staff at the workshop, or to mail their comments before the comment period closed. All written comments received are reproduced in this FEIR, and responses to each comment have been provided. The written comments were accorded the same consideration and treatment given to the oral comments received during the public hearing.

I2 All written comments submitted in response to the August 5, 1998 DEIR, as well as oral statements made at the September 15, 1998 public hearing, are addressed in the Final EIR. Earlier discussions with the commenter (and others) that occurred during EIR scoping meetings were taken into consideration during the preparation of the DEIR. Although not required by CEQA, to the extent possible, comments made by members of the public at the series of four public informational meetings held following publication of the DEIR (August 24 & 25, and September 1 & 2) were also considered in preparing the Final EIR.

I3 How property tax revenues might change is largely a consequence of restructuring under AB 1890, not of divestiture. PG&E must market-value these assets before December 31, 2001, at which point the plants would in any event be reassessed by the Board of Equalization. The valuation and reassessment can be done at *any* time after January 1, 1998. Divestiture is simply one of several methods of establishing that market value, in this case by using an auction. The divestiture process *may* accelerate this market valuation process by up to three years, but it also may not, since alternative valuation methods could be pursued by PG&E within the same time frame in which divestiture would occur.

The CPUC cannot accurately forecast the possible ranges of sale prices for the Geysers, and the resultant tax assessments. In general, the divested plants have sold for more than their book values, resulting in increased property tax revenues for the host counties. Whether the Geysers will sell for above or below book value is one of the unknowns in transforming to a market-based from an administered industrial structure. That said, it is worth noting that PG&E believes the current market to be favorable for achieving a good price, as noted in Chapter 2 (page 2-1). In any event, with the caveat that divestiture may cause reassessment to occur earlier than it would otherwise, any changes in property tax revenue from the Geysers would stem from restructuring and not from this project.

To clarify that the only impacts divestiture may have with respect to reassessment of the plants would be an acceleration of changes that will occur under restructuring, the following is added as the third paragraph on page 4.11-14:

> In considering any changes affecting property tax revenues as a result of the reassessment of the plants, it is important to keep in mind that the effects of divestiture (if any) would be temporary. Restructuring mandated by AB 1890 requires that plants be market-valued by the end of 2001. Once the market value of a plant is established, it would be reassessed by the Board of Equalization. Divestiture is not the only means by which market valuation could be established. It is also noteworthy that PG&E has applied to sell the plants now because it believes current market conditions are favorable for the sale of generating assets, as noted in Chapter 2.

And the following sentence is added to the end of the third paragraph on page 4.11-16 of the DEIR:

> ...physical effects on government services. Because restructuring requires that the market value of the plant be established by the end of 2001, by means of the proposed auction or some other means, any impact divestiture would have on the reassessment of the plant as a result of its valuation would be temporary.

I4 By submission of the comment, the request that the commenter's statement be included in the Final EIR is met, since the Final EIR will include both the comment itself and this response. In response to the statement itself, certainly much of the statement is accurate and was recognized by the preparers of the DEIR. However, the statement covers a very broad set of issues, many of which are beyond the scope of this EIR, (e.g., deregulation of the electric utility industry, injection of wastewater into the Geysers, and the recognition that the Geysers is a "world class " show piece which needs to be promoted). While the commenter's views on these broad issues may or may not be accurate, it is beyond the scope of this EIR to address these issues.

I5 The comment does not pertain to the adequacy of the EIR. Although CEQA mandates the provision of several opportunities to review and comment on the potential environmental effects of a proposed action, which have been provided in the case of the currently proposed project, it does not require the type of project review requested by the commenter. However, the comment will be considered by the decision-makers prior to taking any action on the project.

I6 The new owner would be subject to existing air and water regulations and associated permits required for operation of the plant. With respect to operating protocols, as stated on page 2-7 of the DEIR, PG&E will continue to operate the plants at the direction of the new owner pursuant to an Operation and Maintenance Agreement that would have a term of two years after the sale closes. This Response to Comments document does address (where specific issues are identified) comments related to unwritten operating protocols. See responses to Comments H9, H10, and H11.

I7 For the reasons discussed in the response to Comments H14 and H15 above, it appears that generation from the Geysers units will remain viable for the reasonably foreseeable future. In fact, given the transmission constraints in the region, the financial incentives and benefits available to any new owner of the Geysers units that are not presently available to PG&E, and the ability of the new owner to immediately compete in the direct access market, generation from the Geysers is more likely to increase rather than decrease.

As to the commenter's other suggestions, the CPUC is unaware of any transition floor price made available to PG&E under AB 1890. It is also unaware of any assistance provided to PG&E with regards to the Geysers from AB 1890. Regardless of ownership, the owners of the Geysers are required to collect all of their future or "going forward" costs from power market revenues, i.e., from the Power Exchange, the Independent System Operator, or direct access sales. Although a private owner of the Geysers units would not be eligible for the 1.5 cent/kWh federal subsidy mentioned by the commenter, the new owners may be able to apply to the CEC or the federal government for assistance that was not available to PG&E because of its status as an investor-owned utility. (Please see the responses to H4 through H6 and H13 through H15 for a thorough discussion of incentives and subsidies available to the new owners of the Geysers units.) Whether the new owners apply for this assistance is at their discretion. However, the Geysers units are expected to be economically viable in the restructured market because of their low fuel price compared to fossil-fueled power plants.

I8 Please see response to Comments H4, H5, and H7.

September 20, 1998

Mr. Bruce Kaneshiro
CPUC EIR Project Manager
C/O Environmental Science Associates
225 Brush Street, Suite 1700
San Francisco, CA 94104-4207

Re: Draft Environmental Report, CPUC Application #98-01-008
Geysers Geothermal Power Plant & Other Divestitures

Dear Mr. Kaneshiro,

Thank you for having the workshop at the Little Red School House in Cobb. As you heard at that meeting most are unaware of the legal process and are unlikely to follow up in writing to restate their concerns. Therefore, for the record, I feel that it was inappropriate that people could not submit verbal comments but instead would be required to attend a hearing in San Francisco in order to do so. The purpose of this letter is to formally put on the record several of my concerns and try to repeat some of those concerns that were expressed during that workshop.

[Begin J1]
First and most importantly, our Air Pollution Control Officer stated several times that you are going forward with a sale of "green" power without an assessment of policy or the implications. While you did remark that there was a one and one-half cent per kilowatt advantage given to green power and renewables during ESA/CPUC staff's presentation to the Board of Supervisors, our APCO has continued to contend that those moneys are not available in the Geysers and are available only for new power.[End J1] [Begin J2]Some question exists as to the possibility of that even AB 1890 will not apply once the plants are sold. Please resolve this issue. Also, please identify any incentives or advantage given to green power by state policy, likely to be incorporated into the CPUC's consideration or other state agencies, as this is an important issue to our community at large and to our state and nation. We desire this policy issue to at least be discussed and considered within the divestiture and sale of this first green power by what used to be a monopoly utility. Clearly, the CPUC can condition the sale and policy options may be available.[End J2]

[Begin J3]
Second, the issue of the tax base changing and the manner in which you looked at the economy and the effects upon jobs, etc., was pointed out to be somewhat poorly supported, particularly the conclusion that 1-2% was insignificant causes great concern.[End J3] [Begin J4]The comparison to the work force in Sonoma County versus that of Lake County was another major concern and should be corrected. The local agencies that might be heavily affected by any decision of sale that would result in lesser tax revenue includes the school district, the local fire district, as well as the county.[End J4] [Begin J5]We are concerned that if this impact is significant that there be fair consideration of mitigation and compensation. [End J5] [Begin J6] It is my concern that you try to quantify any such impacts realizing you will not know the selling price of the facilities, but

that you have an obligation to suggest mitigation should the selling price be substantially lower than the present tax base yield value. We realize the reevaluation is likely in two years, but still two years for preparation is significant. Mitigation could perhaps include a payment from Pacific Gas and Electric as part of any sale that would compensate the fire districts, school districts, etc., and cushion the effect. Again, as far as the job market issue, we understand your approach but ask for a consideration of the effect upon Lake County where a majority of workers reside versus that of Sonoma County. [End J6]

[Begin J7]
You heard several comments regarding the sale of the facility and the continuation of programs that are not necessarily regulatory but that have served the community such as the use of mercury scrubbers not being required, but being in place, participating in GAMP, and participating in the seismic studies associated with earthquakes. Instead of suggesting no mitigation, we would suggest a reasonable mitigation of the condition of the sale to require the owner to continue these programs until they are determined to be resolved or unnecessary after discussions with the public and effected agencies. I would also like to reiterate how the Geysers power plants are interrelated with many aspects of our community function and more than just power plants. The classic is the disposal technique we use for our sewer plants, and the other hydro-curtailment resulting in the need for waterlogged wells to be cleared and that resulting in the noise complaints that you heard during the workshop. [End J7] [Begin J8] This is not a simple system, and it is more than just power plants. The Geysers have been largely developed with a realization that green power was good for the state, the county and the country. Such realization should continue through this sale and future operations of these plants. Any step that the CPUC could take in assuring that should be in the final EIR. Mitigation might include: the ISO having "a set a side" to enable them to sell sustaining amounts of power during hydro-curtailments; the state having a distribution added value charge that would compensate in a more general manner for green power such as the Geysers; a green power portfolio requirement for sellers; and/or a method of charging the real cost of nuclear and fossil fueled power. Seeking any needed mitigation early seems especially important given that California and PG&E have a significant installed green power component as part of our present power generation and distribution. [End J8]

[Begin J9
I would reference you to the Board's letter of May 13, 1998, bringing up many of these issues and ask specifically that you consider mitigation for the six items identified therein, and the need for mitigation should the conclusion of "no significant impact" prove not to be the case.
[End J9]

[Begin J10]
Again, I understand that you can take a simple approach but want to reemphasize that: 1) this green power sale is the first of this type in California for a utility, it is of a precedent setting nature, and the manner in which the sale is completed may be a direction without adequate policy considerations; [End J10] [Begin J11] and 2) while CPUC/ESA did a commendable job of trying to address hydro curtailment induced stacking emissions, the seriousness of hydro-curtailment and that it is incompatible with the wise operation of the Geysers steam fields and causes a variety of physical and fiscal problems seems to have been largely missed. [End J11]

[Begin J12]
Finally, the overall profitability of green power in the future and now, cannot be ignored. When you have a company such as PG&E that has the vast majority of the customers, it is incumbent on us all to ensure the transition to market is rational and does not unfairly disadvantage indigenous green power which is small and may have special but reasonable needs to assure continued success.
[End J12]

Sincerely,

Ed Robey
County of Lake
Supervisor District 1

J. LAKE COUNTY BOARD OF SUPERVISORS (Ed Robey)

J1 Please see responses to Comments H14 and H15 above.

J2 Please see responses to Comments H14 and H15 above.

J3 Please see response to I3.

J4 Please see to response to Comment H26.

J5 Please see responses to Comments I3 and K2.

J6 Please see response to Comment I3. The market valuation of the Geysers without divestiture could have occurred at any time after January 1, 1998. Therefore, even though divestiture may accelerate reassessment, quantifying how much sooner this may have occurred would be purely speculative.

J7 Please see response to Comment H11. The issue of potential curtailment of generation at the Geysers during periods of high hydropower availability is unrelated to the proposed divestiture of the power plants, but is addressed in the response to Comment H6. Please see the response to Comment H54 concerning noise issues. Regarding wastewater disposal, the steam field operators have contracts to accept effluent for injection into the steam fields, and these contracts will not be altered by divestiture.

J8 Please see response to Comment H14 above. The policy recommendations offered by the commenter would far exceed the authority of the CPUC. The Independent System Operator (ISO) is an independent state corporation regulated by FERC. The ISO is governed by an independent Oversight Board that periodically reviews ISO policies and makes recommendations for improvements, but major changes to ISO policies would require action by the FERC or by the Legislature or Congress. However, the commenter's suggestion for a distribution added value charge that would compensate in a more general manner for green power such as the Geysers is already in effect, as detailed in the response to Comment H15 above. As to the commenter's other suggestions, previous attempts by the CEC and the CPUC to quantify the real costs (i.e., the cost of environmental damage, or "externalities") of nuclear and fossil-fueled generation foundered because industry players could not reach consensus. As well, consensus could not be reached during the state's previous attempt to mandate a set-aside for renewable energy, requiring service providers to maintain a portfolio of renewable energy resources. With the enactment of AB1890, and the CPUC's preferred policy decision, consumers now have the power to determine the future makeup of the generating mix in California.

J9 The following responses correspond to numbered items listed in the May 13, 1998, letter from Louise Talley, Chairman of the Lake County Board of Supervisors, to the CPUC.

(1) Regarding hydro curtailment, please see response to Comment H6.

(2) Regarding noise mitigation, as stated in Section 4.10 of the DEIR (page 4.10-14), operational noise levels at the Geysers units are not expected to change, or to exceed land use standards as a result of operation by a new owner and no operational noise impacts are expected to occur as a result of operation by a new owner. Section 4.10 also states (page 4.10-15) that steam stacking can result in brief yet substantial noise events. However, a pipe manifold system installed in the mid-1980s (described on page 4.5-47 of the DEIR) has significantly reduced stacking events. The project would not affect operation of the manifold system, so the system's benefits with respect to noise mitigation would continue. Also see response to Comment H54.

(3) Regarding mercury scrubbers, please see response to Comment H11, fourth paragraph.

(4) Regarding GAMP participation, please see response to Comment H11, second paragraph.

(5) Regarding sumpless drilling, neither PG&E nor the new power plant owners would have any drilling operations at the Geysers; any drilling in the area would be conducted by the steam field operators, whose operations are not part of the proposed project.

(6) Regarding preventive maintenance, as noted in Attachment C of the DEIR (page C-29), a non-utility plant owner would have a greater incentive than a utility (such as PG&E) to invest in plant maintenance, in order to maintain a high level of availability. Also see responses to Comments H23 and H64.

J10 Please see responses to Comments H7, H13, H14, H15, and H46 above. The commenter is correct in that PG&E's sale of the Geysers generating units would be the first sale of a "green power" generating asset by a utility in California. However, the issues associated with the sale of the Geysers Power Plant are unique, and the CPUC will make its final decision based on the merits of this EIR, and the evidence and comments submitted in the divestiture proceeding. Any decision made in the case would likely not be precedent-setting merely because no other similar utility-owned green power generating asset exists in California (CEC, *California Power Plant Data Information*, June 1998).

J11 Please see responses to Comments H4, H5, and H7. The issue of economic curtailment at the Geysers is one that arises from restructuring and contract disputes among the current stakeholders, and not from divestiture in any way.

J12 Please see responses to Comments H7, H13, H14, H15, H46, and J8 above.

September 18, 1998

Mr. Bruce Kaneshiro
c/o Environmental Science Associates
225 Bush Street, Suite 1700
San Francisco, CA 94104

Re: Comments from Lake County Community Development Department on the Draft Environmental Impact Report for Pacific Gas and Electric Company's Application for Authorization to Sell Certain Generating Plants and Related Assets

Dear Mr. Kaneshiro,

The County of Lake recognizes and appreciates the extensive research and quality presentation that Environmental Science Associates has devoted to the DEIR. The individualized attention given to the Geysers power plants in Lake County was warranted. Also, the public hearing in the Cobb Mountain area was helpful to Lake County officials and residents.

The Community Development Department has the following comments on the DEIR:

[Begin K1]

1) During the 9/2/98 public meeting at the Cobb Community Center, Lake County Supervisors and residents discussed concerns over the possible abandonment of a power plant due to a new operator going bankrupt or "skipping town". Such a situation would be devastating to the County if the County were to be burdened with clean-up and restoration costs of an abandoned, defunct power plant. Can the Final EIR answer the following questions?

    a) Is the County or is the CPUC the lead agency with regard to clean-up of an abandoned power plant?

    b) Can the Final EIR discuss the feasibility of requiring a new operator to post to the lead agency a financial assurance mechanism such as a surety bond? This would insure that any restoration and environmental clean-up will be funded in case of operator bankruptcy.

[End K1]

[Begin K2]

2) On page 4.11-16 the DEIR discusses impacts on public services. The DEIR notes "The Geysers Power Plant generates an estimated $920,000 per year in property taxes to Lake County, which is about 2.8% of the County's total property tax revenues. Proportionately, the Geysers generates more property tax revenues to Lake County than any of the other power plants being considered for divestiture." The DEIR goes on to conclude that "... it is unlikely that the decrease (property tax revenue) would lead to adverse physical effects on government services." A decrease in property tax revenue would be a significant impact to Lake County government services. The County is not a wealthy county and has a high percentage

of retirees and individuals on various social welfare programs. The current County budget already falls short of funding needs.

Can the FEIR recognize that a decrease in property tax revenue would be a significant impact to Lake County and evaluate the following proposed Mitigation Measure?

a) Should property tax revenues to Lake County decrease, the CPUC shall fund the amount of the decrease to Lake County for three years to allow the county to maintain government services while seeking a long term solution to the decrease in property tax revenue.

[End K2]

[Begin K3]

3) Page 5-10 discusses the Basin 2000 Project. It is my understanding that this project has been subject to budgetary cuts when the last state budget was finalized. If so, can the FEIR discuss how these budgets cuts will impact the future operations and planning for the Lake County units?

[End K3]

Thank you for taking my comments under consideration. Please feel free to contact me at (707) 263-2221 if you have any questions.

Sincerely

/s/

Dave Wappler
Environmental Officer

cc: Lake County Board of Supervisors
Robert Cervantes, Community Development Director

K. LAKE COUNTY COMMUNITY DEVELOPMENT DEPARTMENT (Planning Division)

K1 Public Utilities Code Section 377 removes much of the CPUC's regulatory authority over utility generation plants after these plants are market valued—an event mandated by AB 1890 even if divestiture does not occur. Consequently, lead agency responsibility for clean-up of an abandoned power plant would fall to the County. However, if soil and/or groundwater contamination were present, lead agency responsibility could fall to the Department of Toxic Substances Control and/or the Regional Water Quality Control Board.

As noted in the DEIR, under terms of the Purchase and Sale Agreement, PG&E will identify and retain liabilities associated with soil and groundwater contamination existing prior to sale (unless caused by a purchaser, steam supplier or land owner, in addition to other limited exceptions) and off-site disposal prior to sale (with certain limited exceptions). PG&E will also retain any liabilities associated with ongoing operations of assets or interests that it does not sell. To control the potential costs associated with these liabilities, the proposed Purchase and Sale Agreement gives PG&E the right to conduct post-sale remediation. PG&E would be responsible for remediating the contamination for which it retains liability if and when such remediation is required by law. The buyer will be required to indemnify PG&E against liabilities arising from buyer and third-party post-sale activities. In addition, the buyer will agree not to develop the site for residential or certain other uses and will be responsible for returning the site to its natural condition upon any required decommissioning. Please see response to Comment B5 for additional information on decommissioning requirements.

Regarding posting a bond, as discussed below, such a requirement is now imposed on steam field operators at the time of transfer of ownership. However, these requirements pertain to the steam field operators, not the power plant owners. Consequently, divestiture will not affect or implicate these requirements in any way. No mechanisms currently exist by which to require the new power plant owners to post a bond to ensure proper environmental clean-up, though, as noted in response to Comment B5, a variety of legal obligations pertain to decommissioning. Also as noted in the response to Comment B5, there would be no reasonably foreseeable increase in the risk of environmental impacts occurring during decommissioning under a new owner. In addition, the CPUC will ensure that the new owners are financially responsible and viable entities to operate the plants. There would be no impact on environmental clean-up associated with the project, and therefore no such mitigation as required by the commenter would be required.

Section 3723.5 of the Public Resources Code requires any person who acquires ownership or operation of any geothermal well or wells to post with the State Oil and Gas Supervisor (California Department of Conservation, Division of Oil, Gas, and Geothermal Resources) an individual indemnity bond for $25,000 for each well acquired, or a blanket indemnity bond for $100,000 for any number of wells acquired. The bond is intended to secure the State against all losses, charges, and expenses incurred by it to obtain compliance by the well owner with all of the provisions of Chapter 4 (commencing with Section 3700) of Division 3 of the Public Resources Code requirements pertaining to drilling, redrilling, deepening, maintaining, or abandoning any geothermal well. The bond remains in effect until the well or wells covered by the bond have been properly abandoned or the bond has been substituted by another valid bond. Proper abandonment requires a demonstration to the satisfaction of the State Oil and Gas Supervisor that all necessary steps have been taken: 1) to protect underground or surface water suitable for irrigation or farm or domestic uses from the infiltration of any harmful substance, and 2) to prevent the escape of all fluids to the ground surface. Abandonment must be accomplished in accordance with requirements specified in Chapter 4 of Division 3 of the Public Resources Code, which include notification and reporting requirements and oversight by the Oil and Gas Supervisor. Failure to comply with Chapter 4 is punishable by a fine of up to $1,000 and/or imprisonment for up to six months for each offense.

In 1997, a proposed bill to increase the existing bond requirement to $1.5 million died in committee. The California Department of Conservation is hoping to find a sponsor to reintroduce the bill at the next legislative session.

K2 Please see response to Comment I3. As it clarifies, changes in property tax revenues (if any) would ultimately be the consequence of restructuring, not divestiture. The only impact divestiture may have with respect to the reassessment of the power plants would be an acceleration of changes that will occur under restructuring, because P&E must market-value its generation assets by the end of 2001. Whether the Geysers will sell for above or below book value is an unknown the CPUC cannot accurately forecast at this time. That said, it is worth noting that PG&E believes the current market to be favorable for achieving a good price, as noted in Chapter 2 (page 2-1). This is especially true for the Lake County units because the steam from the Lake County (Calpine) steam field is considerably higher quality than the steam from fields in Sonoma County. However, even if the appraised value of the Lake County generating units were to fall to half their present value, the resultant 1.4 percent reduction in property tax revenues paid to the County would not meet the definition of a “significant impact” under the CEQA Guidelines. Section 15002(g) of the CEQA Guidelines defines a significant effect on the environment as “a substantial adverse change in the physical conditions which exist in the area affected by the proposed project.” While a loss of 1.4 percent in property taxes could affect the services provided by Lake County, this loss would not be likely to cause a substantial decrease in government services or adverse physical effects on government facilities. As for the commenter’s suggested mitigation measure, the CPUC has no authority to allocate funds to compensate Lake County in the unlikely event of a drop in property tax revenues resulting temporarily from divestiture or from restructuring the electric utility industry.

K3 Budget changes for the Basin 2000 project would have no effect on the future operations and planning for the Lake County units because the Basin 2000 project would not increase or decrease the amount of water injected into the Lake County steam field. Rather, wastewater generated by the Basin 2000 project would merely displace raw lake water currently diverted from Clear Lake into the Southeast Geysers effluent pipeline. The total volume of water sent up to the Lake County steam fields would not change whether or not the Basin 2000 project is funded and constructed.

September 21, 1998

Mr. Bruce Kaneshiro, Project Manager
c/o Environmental Science Associates
225 Bush Street, Suite 1700
San Francisco, CA 94104

Re: Comments on the Draft Environmental Impact Report for Pacific Gas and Electric Company's Proposed Divestiture Application No. 98-01-008

Dear Mr. Kaneshiro:

PG&E hereby submits the attached comments on the Draft Environmental Impact Report (Draft EIR) for PG&E's proposed divestiture of its Potrero, Contra Costa, Pittsburg, and Geysers Power Plants. The comments are provided in two sections; the first section contains general comments and the second section contains specific comments by page number.
PG&E appreciates the opportunity to comment on the Draft EIR, and urges the Commission to certify the EIR as final as soon as possible.

If you have any questions, please call me at (415) 973-1595.

Sincerely,

Cecilia Montana

Cecilia F. Montana
Acting Director, Divestiture and Gas Ratemaking

Attachment

PG&E'S COMMENTS TO THE CPUC
ON THE DRAFT EIR FOR PG&E'S APPLICATION NO. 98-01-008
September 21, 1998

GENERAL COMMENTS

1. Conservative Nature of the Analytical Methodology. PG&E would like to underscore the first sentence in the section of the Draft EIR that describes the analytical methodology employed throughout the document. The Draft EIR states, "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" (page 3-1).

Due to the uncertainty inherent in predicting the behavior of PG&E and new owners in the new restructured market, the analysts created hypothetical scenarios. Some scenarios predicted what PG&E's behavior might be in the future and other scenarios predicted the behavior of unknown future plant owners.

[Begin L1]
While creating the scenarios, the EIR drafters had a wide array of assumptions from which to choose. The drafters consistently selected the most conservative assumptions, that is, the assumptions that would result in the greatest potential for environmental impacts. This process was repeated for each of the scenarios so that the analysis would represent a reasonable worst case. The analysis therefore overestimates the potential for environmental impacts.
[End L1]

This consistent leaning toward the worst case resulted in scenarios that the EIR characterizes as unlikely. For example, the fundamental basis for the analyses is that new owners might operate the plants at higher levels than might PG&E. The EIR cautions that "the degree to which generation would increase at the plants slated for divestiture is highly uncertain" (page 3-8). Further "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" (page S-8).

[Begin L2]
One of the most influential assumptions in the analysis is that, for new owners of the fossil-fueled plants but not PG&E, "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" (page 3-12). This assumption is an artificial construct. It was used to force the computer model to move in the desired direction, that is, toward a greater potential for environmental impact. As the EIR points out, "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" (page 3-12).
[End L2]

[Begin L3]
It is indeed unlikely that a new owner would ignore the price of fuel in its decisions. It is also highly unlikely that a new owner, and only a new owner, would be able to purchase natural gas for 25 percent less than its California competitors. It is more likely that similar gas prices would be available for all generators and the generator with the most favorable economics would tend to generate more than one with less favorable economics. In any case, total generation would be limited by overall demand. Nevertheless, PG&E recognizes that the Draft EIR analysts employed this conservative approach in order to examine the greatest potential for environmental impacts. As such, the potential

impacts identified in the EIR are indeed only potential, and are potential only under an extreme set of circumstances. The projections should not be used or relied upon for purposes of reasonable economic forecasting.
[End L3]

[Begin L4]
2. New Owners of the Geysers Geothermal Plant. Alternative 3 in the Draft EIR evaluates whether there might be an environmental benefit if the Geysers plants were sold to the steam field operators. The analysis concludes that to do so would be environmentally preferable, as it "would allow for greater coordination of generating unit operations with steam field characteristics and may reduce steam stacking" (page 6-28). This is an inappropriate "conclusion" for two reasons.

First, the alternative presumes that there would be "greater coordination". This is an assumption embedded in the design of the alternative (page 6-23), not a conclusion derived from analysis. No evidence is presented that current operations are not now coordinated nor that they could be more coordinated.

In fact, PG&E's contract with UNT to supply steam for the units in Sonoma County and PG&E's contract with Calpine to supply the steam for units in Lake County both require the companies to coordinate operations[1]. To do so, the companies have instituted operational procedures and monitoring equipment specifically to prevent unabated steam releases, or "steam stacking".

Steam stacking can occur when generation is reduced. Such reductions may be scheduled or unscheduled. In the case of scheduled reductions, such as for unit maintenance, the steam field agreements require PG&E to notify the steam field operators at least 48 hours in advance. In the case of unscheduled reductions, monitors installed on PG&E's generating units and the steam suppliers' steam gathering systems immediately transmit changes in generation and steam pressure. The signals from the monitors are automatically relayed to Unocal's and Calpine's control centers, which are staffed 24 hours a day. When a signal is received, the steam suppliers automatically throttle the wellhead valves, which redirects the steam to other generating units with emissions abatement equipment. This monitoring system has been successfully operating for several years.
[End L4]

[Begin L5]
Secondly, the computer modeling for this alternative assumes that "the existing steam supply contracts would be inapplicable (because the contracting parties would be merged into one steam supplier/plant owner for each unit) and the price of steam to the plants would decline" (page 6-6). The modeling results show that the Geysers plants would operate more under Alternative 3 than under the other scenarios. The Draft EIR concludes that, due to this increase in operations, there would be less steam stacking. While the computer modeling results show a significant increase in year 1999, the increase is slight by the year 2005. In 2005, the modeled annual plant capacity factors under the proposed project (Cumulative Analytical Maximum Scenario), continued ownership by PG&E (Draft EIR Alternative 1), and ownership by the steam field operators (Alternative 3) are 87, 90, and 93 respectively (page 6-7). Thus, according to the model, the increase would be 6 percent averaged over 14 units. Due to the infield systems to prevent unabated steam releases, such an increase in operations would not result in a significant benefit, if any.
[End L5]

[1] See Section 5 of PG&E's Agreement for the Sale of Geothermal Steam Between Thermal Power Company and Pacific Gas and Electric Company Dated July 28, 1992 (as amended August 22, 1993), Agreement for the Sale of Geothermal Steam Between Union Oil Company of California and Pacific Gas and Electric Company Dated September 30, 1991 (as amended August 22, 1993), Agreement for the Sale of Geothermal Steam Between NEC Acquisition Company and Pacific Gas and Electric Company Dated September 30, 1991 (as amended August 22, 1993). See also, Section 8 of PG&E's Agreement for the Sale and Purchase of Geothermal Steam Between Signal Oil and Gas Company [a.k.a. Calpine] and Pacific Gas and Electric Company Dated March 23, 1973.

[Begin L6]
As the Draft EIR notes, the analysis of the proposed project does not indicate that the project would result in any change related to steam stacking. "Therefore, this alternative would not be necessary to reduce project impacts. It may, however, beneficially reduce steam stacking and release events" (page 6-24). In PG&E's opinion, Alternative 3 has not demonstrated that selling the Geysers units to the steam field operators would be any more or less environmentally preferable to selling the units to a third party. It should also be noted that the steam field operators have a right of first refusal to purchase these units, as stated elsewhere in the Draft EIR.
[End L6]

[Begin L7]
The CPUC has no responsibility to choose the environmentally preferable alternative. The California Environmental Quality Act (CEQA) Guidelines require that the lead agency identify an environmentally superior alternative among other alternatives analyzed[2]. However, CEQA does not require the agency to choose the most environmentally desirable alternative if the agency has reduced the project's environmental effects to an acceptable level through mitigation.[3] The CPUC does not have authority to order the sale of the plants to a particular buyer without PG&E's consent.
[End L7]

[Begin L8]
3. Cumulative Analysis. In Section 5.2.2, the EIR describes the assumptions made in the cumulative analysis regarding new generation to replace the Hunters Point Power Plant. The EIR notes on page 5-4 that:

> "The exact size, mix and location of facilities that will ultimately be proposed and approved to replace the Hunters Point Power Plant is speculative. However, in order to portray and evaluate (in at least a generalized nature given the paucity of definitive data and plans) the maximum potential for change in the context of the cumulative impact analysis for this project, it is assumed for purposes of this EIR that new generation facilities would be constructed by 2005 to serve the City's electricity needs. This cumulative analysis assumes that the new facilities would consist of two new combined-cycle electric generating units sized at 240 MW each (totaling 480 MW)."

PG&E would like to underscore that the facility assumed in the cumulative analysis is a hypothetical facility. The generation and/or transmission facilities that will replace the power and reliability now provided by the Hunters Point plant are not known at this time. It will be incumbent on the proponents of the new facilities, and the agencies that must approve the project(s), to evaluate, in compliance with the California Environmental Quality Act, the potential for project-specific and cumulative environmental impacts associated with the new facilities and to address any significant environmental effects.
[End L8]

SPECIFIC COMMENTS BY DRAFT EIR SECTION

EXECUTIVE SUMMARY

[Begin L9]
Page S-4, Figure S.2. Please note that PG&E will also continue to own the Diablo Canyon Nuclear Power Plant, located in San Luis Obispo County. (The same figure is used as Figure 2.1 on page 2-3.)
[End L9]

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[2] See, 14 Cal. Code Regs. 15126(d)(4).
[3] See, Laurel Heights Improvement Association v. Regents of the University of California, 47 Cal. 3d 376, 402 (1988); Kosta, Stephen L. and Zischke, Michael H., Practice Under the California Environmental Quality Act sections 17.20 - 17.22, pgs. 656 - 663.

[Begin L10]
Page S-5, paragraph 3. The paragraph states that "PG&E will retain facilities and equipment at each site that pertain to transmission or distribution operations." Please note that PG&E will divest a small portion of the transmission lines at the Geysers Power Plant, as stated elsewhere in the document (e.g., pages 2-7, 2-28, and 4.12-17).
[End L10

[Begin L11]
Page S-5, paragraph 4. The Summary states that "The Purchase and Sale Agreement for each plant requires a deed restriction that prevents the new owner from using the site for residential or other sensitive uses." This is true for the fossil-fueled plants. However, for the Geysers plant, the Purchase and Sale agreement requires the purchaser to agree to a land use covenant that will require the purchaser (and its subsequent transferees, if any) not to use the property for residential or other sensitive uses. (See also pages 4.1-13 and 14.)
[End L11]

[Begin L12]
Page S-21, Table 2.6. Please note that the levels of significance indicated for Impacts 4.5-4, 4.5-5, and 4.9-3 for the proposed project should include an "(M)" to indicate that the EIR has identified supplemental mitigation for each of these impacts.
[End L12]

2. PROJECT DESCRIPTION

[Begin L13]
Page 2-5, paragraph 2. Please replace the last sentence regarding PG&E's hydroelectric assets with "PG&E is currently considering various options for market valuation of its hydroelectric assets".
[End L13]

[Begin L14]
Page 2-20, paragraph 2. All three boilers associated with Units 5, 6, and 7 are capable of burning residual fuel oil.
[End L14]

[Begin L15]
Page 2.42, paragraph 2. The Draft EIR states that "Early reinjection of wastewater from the Southeast Geysers effluent pipeline have been encouraging. There has been about a 7 percent (60 MW) increase in capacity in the Southeast Geysers field as reported by staff at the Geysers Power Plant." Upon closer examination of the peak output achieved by the four PG&E plants that are in the Southeast area of the steam field, PG&E believes that 7 percent overstates the increase. A more accurate estimate would be that there has been about a 5 percent increase in capacity. In addition, given the design capacities of the four Southeast Geysers Units (Units 13, 16, 18, and 20) listed on Table 2.1 (pages 2-8 and 9), it appears that the 7 percent increase resulting in a 60MW increase is a miscalculation
[End L15]

[Begin L16]
Pages 2-44 and 45, Table 2.3. (1) There is also a lease from the State Lands Commission for public land associated with the Contra Costa plant. (2) Note that the Aboveground Petroleum Storage Tank requirement applicable to the Geysers plant is not a permit per se. The requirement includes a biannual statement, registration fee, and SPCC plan.
[End L16]

4.4 WATER RESOURCES

[Begin L17]
Page 4.4-5, paragraph 1. The last sentence states that "Sodium hypochlorite is regularly applied in the condensers to minimize growth of biological organisms and is then discharged". Please note that, in accordance with the NPDES permit for the plant, the sodium hypochlorite is neutralized with sodium bisulfate before discharge.
[End L17]

4.5 AIR QUALITY

[Begin L18]
Page 4.5-14, paragraph 3. Note that since the beginning of 1994, PG&E has essentially ended using fuel oil. However, fuel oil may still be used in limited circumstances. Under BAAQMD Regulation 9, Rule 11, only natural gas is to be burned in these units, except during force majuere natural gas curtailment and very limited testing.
[End L18]

[Begin L19]
Page 4.5-24, paragraph 2. The paragraph states "Unit 3 is coupled to a single boiler, which is capable of burning natural gas or fuel oil; however, since 1995, only natural gas has been burned because of Regulation 9, Rule 11". The sentence could leave the misimpression that the switch to natural gas occurred because of Regulation 9, Rule 11. However, the fuel switch was made prior to when the regulation became effective in 1997. The sentence could be clarified by stating, "since 1994, PG&E has only burned natural gas and Regulation 9, Rule 11 requires that natural gas be burned except in very limited circumstances".
[End L19]

[Begin L20]
Page 4.5-34, last sentence. Please delete the reference to the mobile combustion turbine at the Contra Costa plant. It is no longer at this plant.
[End L20]

[Begin L21]
Page 4.5-39, last paragraph. The paragraph incorrectly states "While two of the seven boilers are permitted to burn either natural gas or fuel oil, all of them currently burn only natural gas." All seven boilers are permitted to burn fuel oil as long as permit and rule conditions are followed.
[End L21]

[Begin L22]
Page 4.5-47, paragraph 4. The paragraph refers to measurements of radon at the Geysers plant "that indicated levels of radon ranging from 3 to 5 pico-curies per liter of air, which is above typical background levels of 1 pico-curie per liter (1998, personal communication with Lake County APCD)". This range is substantially higher than the measurements reported as part of Geysers Air Quality Monitoring Program (GAMP), which measures radon at two monitoring sites in public areas of the Lake County geothermal area that are downwind of the plant. The most recent quarterly GAMP report of April 1 to June 30, 1998, which reported data for January, February, and March 1998, reported a radon range of 0.1 to 0.5 pico-curies per liter (pCi/l), with an average of 0.2 to 0.3 pCi/l. These measured levels are about 1/10th of the levels identified in the Draft EIR.
[End L22]

[Begin L23]
Page 4.5-61, last sentence. The Draft EIR indicates that the air quality modeling was performed using the AP-42 emissions factors that the U.S. EPA released earlier this year (per U.S. EPA reference listed on page 4.5-84). The Draft EIR refers to these factors as "new, more accurate data reported by EPA for

combustion units". PG&E questions whether the new factors are indeed more accurate. The new factors for PM-10 are based on a very small sample – only four tests nationwide. In addition, for the first time, the EPA has reported separate emissions factors for the filterable fraction of PM-10 and a condensable fraction. There is reason to believe that the condensable fraction is purely an artifact of the sampling procedure as a result of nitrates or sulfates present in the exhaust steam. The EPA has itself indicated little confidence in the factor for the condensable fraction. On a scale of A to E, with A being the highest confidence, the EPA rates its confidence in the factor for the condensable PM fraction for boilers as D. If only the filterable fraction is used in the emission factors, the modeled PM-10 results would drop by a factor of 4.
[End L23]

4.7 BIOLOGICAL RESOURCES

[Begin L24]
<u>Page 4.7-30, paragraph 3.</u> The fourth sentence states "The revised draft HCP (dated April 22, 1998) and associated permit application documents have been reviewed and deemed completed by USFWS and NMFS staff in June 1998." To date, PG&E has not received the certificate of completion. Please delete the sentence.
[End L24]

[Begin L25]
<u>Page 4.7-30, paragraph 3.</u> To update the paragraph, in the fifth sentence, please delete "intend to adhere to" and replace with "concur with", and delete "July 1998" and replace with "September 1998". Similarly, in the last sentence of the paragraph, replace "staff" with "proposed" and replace "October 1998" with "December 1998".
[End L25]

[Begin L26]
<u>Page 4.7-31, second bullet.</u> As required by the federal agencies, the funding is now to be maintained in "a special deposit account".
[End L26]

[Begin L27]
<u>Page 4.7-35, paragraph 3.</u> The federal agencies have emphasized that the Implementing Agreements and HCPs are not transferred, but are part of the permit and reissued along with the reissued permit. As such, in the fourth sentence, please delete "and transfer of the draft Implementing agreement" and substitute with "including the related Implementing Agreement", and delete "to the new owner".
[End L27]

[Begin L28]
<u>Page 4.7-35, paragraph 3.</u> To update this paragraph, please delete the two sentences that begin with "USFWS has proposed" and end with "within a 60-day period", and replace with "The USFWS has concurred with this language".
[End L28]

[Begin L29]
<u>Page 4.7-35, paragraph 3.</u> For clarification, please revise the last sentence as follows: "Accordingly, if the Section 10 Permits are issued to PG&E at least 60 days prior to closing, the permits should be reissued to the new owner at closing, and the new owner will be subject to the restrictions of such permits and the CESA MOU to the same extent PG&E would have been.
[End L29]

[Begin L30]
Page 4.7-36, paragraph 3. For clarification, please delete "As a condition of closing the sale, the new owner will be required to obtain" and replace it with "If the Section 10 permits have been reissued to PG&E prior to closing, the new owner will be required to seek".
[End L30]

[Begin L31]
Page 4.7-37, top of the page. Under "Timing", to capture all of the monitoring actions associated with the mitigation measure, please revise the sentence to read: "Documents should be provided to the CPUC at least forty days before the title transfer, copies of the letters should be provided to plant managers at the close of sale, and the Section 10 Permits should be provided to CPUC when obtained."
[End L31]

[Begin L32]
Page 4.7-37, Level of Significance after Mitigation. For clarification, the term "Operational Constraints" should be in lower case as it is no longer a defined term. Also, please insert after "operational constraints", the phrase "in PG&E's Section 10 Permits and the HCP".
[End L32]

4.9 HAZARDS

[Begin L33]
Page 4.9-4, last paragraph. The section states that "No acutely hazardous materials are used or stored at the Potrero Power Plant." However, lead-acid batteries are used at the plant; the sulfuric acid in the batteries is classified as an acutely hazardous material.
[End L33]

[Begin L34]
Page 4.9-5, last paragraph. In the last sentence, for accuracy, please delete "adversely" and replace "throughout the entire plant area" with "in areas of the plant".
[End L34]

[Begin L35]
Pages 4.9-6, 9, 11, and 13, Phase II testing. PG&E has now completed Phase II testing for all four plants. Risk Assessments have been completed for the Potrero, Contra Costa, and Pittsburg plants. A Risk Assessment is currently being prepared for the Geysers plant.
[End L35]

[Begin L36]
Page 4.9-17, paragraph 1. The Draft EIR states, "The appropriate lead agency at each plant will be selected by means of the Site Designation Process Under the Unified Agency Review of Hazardous Material Release Sites". It is likely that the lead agency for each plant will be selected by the Site Designation Process. However, other selection processes may be used to honor other processes and arrangements with local agencies in place at the time. PG&E recommends that in the quoted sentence, the words "will be" be replaced with "will likely be".
[End L36]

[Begin L37]
Page 4.9-19, paragraph 3. Please note that ammonia is not currently used in emissions abatement equipment at the power plants to be divested.
[End L37]

4.11 PUBLIC SERVICES

[Begin L38]
Page 4.11-16, paragraph 2. The Geysers Power Plant generates an estimated $920,000 per year in property taxes to Lake County (not $920,000 million).
[End L38]

4.12 UTILITIES AND SERVICE SYSTEMS

[Begin L39]
Page 4.12-3, transmission section, paragraph 2. Note the transmission corridor that serves San Francisco and the former Skyline District is rated at about 750 MW assuming the underground 230 kV cable is not available.
[End L39]

[Begin L40]
Page 4.12-5, last paragraph. Regarding the transmission lines, please delete the clause “to protect the in-city on-line generation from potential crippling damage”. The lines are automatically opened, not to protect generation, but to ensure service to the network load. The generators are equipped with their own underfrequency relays to protect them from damage.
[End L40]

[Begin L41]
Page 4.12-7, paragraph 2. (1) Note the CPUC is not served by the network load. (2) Please delete “and in BART trains under the bay”. While the BART stations are served by the distribution network, traction power to run the trains is served from a dedicated substation in San Francisco.
[End L41]

[Begin L42]
Page 4.12-7, paragraph 4. (1) Note that the SFOC require the Dispatcher to load San Francisco generation at differing percentages based on the load. At 800 MW required operating capacity, 40 percent is required; at 700 MW, 30 percent is required. The sentence could be corrected by replacing “40 percent” with “certain portion”. (2) In the paragraph’s last sentence, please delete “not”. During off-peak periods, the SFOC is intended to sustain some, if not all, of the much-reduced downtown loads.
[End L42]

[Begin L43]
Page 4.12-9, paragraph 1. Please delete the word “single”, as there are multiple lines between San Francisco and the outside power transmission grid.
[End L43]

[Begin L44]
Page 4.12-9, last paragraph. For accuracy in the first sentence, please replace “and replacement of 430 MVA transformers” with “and replacement with two 420 MVA transformers”.
[End L44]

5.0 CUMULATIVE IMPACTS

[Begin L45]
Page 5-11, paragraph 2. The section states that "PG&E is one of the key players in the Santa Rosa Wastewater Modified Geysers Recharge Project. However it is assumed that if PG&E were to sell its units, the new owners would simply assume PG&E’s role in the process." These two sentences overstate PG&E's involvement with the project. PG&E is not a party to the contract signed by the City of Santa Rosa and Unocal-Thermal, nor has PG&E entered into separate agreements with the

steam suppliers as it did for the Southeast Geysers Pipeline Project. PG&E recommends deleting the two sentences.
[End L45]

6.0 ALTERNATIVES ANALYSIS

[Begin L46]
Please see the General Comment above regarding New Owners of the Geysers Geothermal Plant.
[End L46]

ATTACHMENT C: SYSTEM ECONOMIC AND OPERATIONAL CHARACTERIZATION

[Begin L47]
PG&E questions Attachment C's conclusion, and the underlying statements that lead to the conclusion, that new owners of the plants would tend to operate the plants at higher levels in the future than would PG&E. According to Attachment C's authors, three primary factors could influence increased generation: the portfolio effect, fuel procurement practices, and the ability of new owners immediately to participate in the direct access market. The discussions of these factors unfortunately contain inaccurate and speculative statements. However, PG&E recognizes that the resulting conclusion of increased generation is embedded as an assumption in many parts of the Draft EIR analyses and serves to further the conservative nature of the analyses. Thus, PG&E is choosing to not submit detailed comments on Attachment C. Please note that by accepting Attachment C's conclusion solely for the purpose of an assumption in the Draft EIR analyses that leads to increased generation, PG&E is not accepting Attachment C's statements, analyses, nor conclusions for any other purpose.
[End L47]

ATTACHMENT E: HAZARDOUS MATERIALS AND WASTE

[Begin L48]
Please see the comment for pages 2-44 and 45, Table 2.3.
[End L48]

ATTACHMENT F: GEYSERS POWER PLANT FACILITY LAYOUT MAPS

[Begin L49]
There are several minor inaccuracies on these maps. Please note that while the inaccuracies do not affect the EIR analyses or conclusions, these maps should not be relied on for purposes other than this EIR.
[End L49]

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PROJECT APPLICANT

L. PACIFIC GAS AND ELECTRIC COMPANY

L1 As discussed in Section 3.1 of the DEIR, due to the uncertainty involved in predicting future behavior of either PG&E or new plant owners, a conservative approach to the analysis in this EIR was employed. Such assumptions, as the commenter points out, “would result in the greatest potential for environmental impacts.” Given this, the DEIR may, in some instances, very well overestimate potential environmental impacts resulting from the project. This approach was necessary to ensure that, even if these environmental impacts were potentially overestimated, environmental effects identified would be evaluated and mitigated appropriately.

L2 As discussed generally in response to Comment L1, the commenter points out specifically one of many conservative assumptions utilized in the analysis. The commenter is correct that this assumption (greatly reduced natural gas supply costs) further strengthens the conservative nature of the impacts analysis.

L3 Comment noted.

L4 “Greater coordination” as used in the instances described by the commenter extends beyond mere notification of events that might lead to steam stacking. The assumption of “greater coordination” for the environmentally preferable alternative was made for several reasons. First among those is a simple “common sense” determination: decision-making among two parties is more difficult than decision-making by one party, especially if the two parties in the former case have different corporate strategies and motivations. Second, the business relationship between PG&E and the steam field owners by all accounts has occasionally been adversarial in the past, and disputes among the parties continue. Third, the steam field operators have insisted that PG&E’s operations at the Geysers “promotes wasteful and inefficient use of fuel,” and that PG&E “has declined to make numerous investments and operating changes that would prolong resource life” at the Geysers (please see Comment P12). Thus, if the steam field owners were to purchase PG&E’s Geysers generating units, the fact that one entity would act to obtain maximum benefit from both the generating units and the steam fields would likely ensure greater coordination of steam field operations with generating unit operations, and would likely result in a greater overall benefit to the environment. For example, a single owner of both the steam field and the generating units may choose to bid into the Power Exchange (PX) at a price low enough to ensure some level of minimum generation at the Geysers, and thus avoid potential damage to the steam field resulting from shutting in the steam, even if the owner would lose money on the power sold during those times. By contrast, PG&E has operated its units based solely on benefits to its shareholders, and ceases operations the instant that continued generation becomes uneconomic, regardless of any potential damage to the steam field.

In addition, noted in Attachment C of the DEIR, the steam suppliers would face effective steam prices that are well below the off-peak PX prices because they would only have to recover steam production costs, rather than the administered prices in the steam supply contracts. Therefore, they would be likely to cycle the Geysers plants less than PG&E currently does in response to fluctuations in demand and in PX market price. This would result in a greater capacity utilization of the Geysers units, which could reduce stacking and the unabated air emissions associated with stacking. Therefore, the DEIR conclusion that Alternative 3 is environmentally preferable to the proposed project is well founded.

It is important to note, however, that the DEIR concludes only that Alternative 3 "would *allow* for greater coordination of generating unit operations with steam field characteristics and *may* reduce steam stacking" (page 6-29, emphasis added), and does not state with certainty that Alternative 3 would definitely result in greater coordination or in reduced incidences of steam stacking. As well, the DEIR does not conclude that the operations of the generating units and steam fields are currently " not coordinated" as implied by the commenter, merely that having a single entity controlling both operations "allows for greater coordination." Furthermore, the DEIR points out (on page 6-26) that the project itself "is not expected to have any adverse impacts with respect to steam stacking." Thus, while Alternative 3 may provide environmental benefits in comparison to the existing setting (with PG&E owning the Geysers units), it would not alter or alleviate any significant environmental impacts associated with the project.

L5 The determination that Alternative Three should represent the Geysers component of the environmentally superior alternative is not based solely on the level of operations of the Geysers units, but it is also based on the greater potential for coordination between the steam fields and the plants. Please see response to Comment L4 for the bases for conclusions with respect to Alternative 3.

L6 Please see responses to Comments L4 and L5 with respect to the selection of the environmentally superior alternative. The DEIR notes in several locations that the steam field operators have the right of first refusal to purchase the Geysers Power Plant. It is also noted in the discussion of Alternative 3, on page 6-24 in the fourth full paragraph, second sentence.

L7 The commenter is correct that CEQA does not require that the environmentally superior alternative be selected. As acknowledged on page 6-24 of the DEIR (fourth paragraph), it is not certain that the CPUC could order PG&E to sell its facilities to a particular buyer.

L8 Comment noted.

L9 Figure S.2 on page S-4 of the DEIR and Figure 2.1 on page 2-3 of the DEIR show only the status of the PG&E fossil-fueled power plants and the Geysers Power Plant. These figures do not show the location or status of other PG&E power plants, including 112 hydroelectric units, and the Diablo Canyon Nuclear Power Plant in San Luis Obispo County. The status of these other power plants is discussed in the DEIR in the last paragraph on page S-5.

L10 Page S-5 (third paragraph, second sentence) is hereby amended as follows:

> PG&E will retain facilities and equipment at each site that pertain to transmission or distribution operations with the exception of a small portion of the transmission lines at the Geysers Power Plant.

Please note that the DEIR already states (on page 2-7, first paragraph) that PG&E will divest its 21-kV distribution and 4-kV service lines at the Geysers plant.

L11 The commenter is correct. Although the effect of both types of agreements is to prevent future residential use (or other sensitive uses) of the property, the legal mechanisms would vary, as noted by the commenter. Page S-5 of the DEIR (third paragraph, fifth sentence) is hereby amended as follows:

> The Purchase and Sale agreement for each of the fossil-fueled plants requires a deed restriction that prevents the new owner from using the site for residential or other sensitive uses. The same restriction will be created on the Geysers Power Plant transfers by means of a land use covenant whereby the purchaser (and its subsequent transferees, if any) agrees not to use the property for residential or other sensitive land uses.

Similarly, page 4.1-13 of the DEIR (first paragraph under Impact 4.1-1, second and third sentences) is hereby amended as follows:

> As a result, the new power plant owners would be subject to local environmental permits (e.g., water and air quality), and local land use agreements (e.g., easements, ~~and~~ deed restrictions, and covenants). Furthermore, PG&E's Purchase and Sale Agreement for each of the fossil-fueled plants will require a deed restriction that prevents development of residential and other sensitive uses on the site, while the buyers of the Geysers plants will be required to sign a land use covenant, which would transfer to any future owners, prohibiting residential and other sensitive uses of the property.

L12 Page S-21 (Impact 4.5-4, significance level for proposed project) is hereby amended as follows:

> NS(M)

Page S-21 (Impact 4.5-5, significance level for proposed project) is hereby amended as follows:

> S/UN(M)

In addition, the following definition is added to footnote "a" of Table S.6 (all pages), following the definition for S/UN:

> <u>S/UN(M) = Impact is significant and unavoidable; mitigation is identified to reduce the impact, but not to less-than-significant levels.</u>

Page S-23 (Impact 4.9-3, significance level for proposed project) is hereby amended as follows:

> NS<u>(M)</u>

L13 Page 2-5 of the DEIR (first complete paragraph, last sentence) is hereby amended as follows:

> PG&E is currently considering ~~the divestiture~~ <u>various options for market valuation</u> of its hydroelectric assets.

L14 Page 2-20 of the DEIR (second paragraph, third sentence) is hereby amended as follows:

> ~~Two~~ <u>All three</u> of the ~~three~~ boilers associated with Units 5, 6 and 7 are also capable of burning residual fuel oil.

L15 Page 2-42 of the DEIR (second paragraph, second sentence) is hereby revised to reflect PG&E's updated estimate of improved capacity from the Southeast Geysers effluent pipeline:

> There has been a ~~7~~ <u>5</u> percent (~~60~~ <u>40</u> MW) increase in capacity in the Southeast Geysers field as reported by ~~staff at the Geysers Power Plant~~ <u>PG&E (PG&E Comments to DEIR, September 21, 1998, page 4)</u>.

L16 In order to reflect PG&E's clarification, Table 2.3 is revised to indicate that the Contra Costa plant does require an SLC Marine Terminal/Public Lands Lease. See response to Comment BX1. Note (b) in Table 2.3 is amended as follows:

> Applies only to Administration Center and Operations Center at the Geysers Power Plant. <u>The Aboveground Petroleum Storage Tank requirement applicable to the Geysers plant is not a permit per se. The requirement includes a biannual statement, registration fee, and SPCC plan.</u>

L17 The following text is added to the end of the first paragraph on page 4.4-5 of the DEIR.

> <u>The sodium hypochlorite is neutralized with sodium bisulfate before discharge, in accordance with the NPDES permits.</u>

L18 Page 4.5-14 of the DEIR (third paragraph, third sentence) is hereby amended and a fourth sentence is added as follows:

> Since the beginning ~~end~~ of 1994, use of fuel oil at these plants has ended and, in response to BAAQMD Regulation 9, Rule 11, only natural gas is burned in these plants. However, fuel oil may still be used in limited circumstances such as *force majeure* natural gas curtailment and very limited testing, per BAAQMD Regulation 9, Rule 11.

L19 Page 4.5-24 of the DEIR (second paragraph, third sentence) is hereby amended as follows:

> Unit 3 is coupled to a single boiler, which is capable of burning natural gas or fuel oil; however, since ~~1995~~ 1994, PG&E has only burned natural gas. As previously discussed, burning fuel oil is now prohibited by ~~has been burned because of~~ Regulation 9, Rule 11 (promulgated by BAAQMD in 1997), except under *force majeure* natural gas curtailment and during limited testing.

L20 Page 4.5-34 of the DEIR (fifth paragraph, second sentence) is hereby amended as follows:

> …include lube oil and distillate storage tanks, a gasoline dispensing facility, boiler standby equipment (distillate fire engine ~~and mobile combustion turbine~~), solvent cleaning operations, maintenance coating operations, a wastewater treatment facility, sandblasting, and miscellaneous sources.

L21 Page 4.5-39 of the DEIR (last paragraph, last sentence) is hereby amended to read:

> While ~~two of~~ the seven boilers are permitted to burn either natural gas or fuel oil, all of them currently burn only natural gas (because of restrictions in BAAQMD Regulation 9, Rule 11).

L22 Please see response to Comment T7.

L23 The EPA recognizes that there is uncertainty in emissions measurements of particulate matter, and it is still unclear how much of the fraction should actually be considered. The older emission factors, which usually did not include the condensable fraction, may have underestimated the actual emission factor. Since the condensable fraction may eventually become particulate matter in the atmosphere, EPA policy has been to include the condensable fraction. However, there is no indication on what fraction of the condensable portion would actually become particulate matter in the atmosphere. Thus, including all of the condensable fraction may be a conservative over-estimate of particulate matter emissions from these boilers.

L24 Page 4.7-30, paragraph 3, of the DEIR is hereby amended as follows:

> In order to obtain take authorization under FESA, PG&E has submitted an application to USFWS and NMFS for Section 10 Permits. The HCP and draft

Implementing Agreements between PG&E and the federal agencies were included in this application. In response to comments from the USFWS and NMFS, PG&E has slightly revised the HCP incorporated in the CESA MOU. The revised draft HCP (dated April 22, 1998) and associated permit application documents have been submitted to ~~reviewed and deemed completed by~~ USFWS and NMFS ~~staff in June 1998~~. Based on PG&E's discussion with USFWS and NMFS, the federal agencies ~~intend to adhere to~~ concur with a timeline under which the availability of the draft HCP and draft Environmental Assessment for the Section 10 Permits were ~~will be~~ noticed in the Federal Register in ~~July~~ September 1998. ~~This will initiate a~~ A formal 30-day public review and comment period was held. Comments received during the formal review period will be addressed in a final HCP. According to the ~~staff~~ proposed timeline, the Section 10 Permits will be issued by ~~October~~ the end of 1998.

L25 Please see response to Comment L24.

L26 The following sentence is hereby added to page 4.7-31 of the DEIR at the end of the second bullet point:

The funding will be maintained in a special deposit account;

L27 Page 4.7-35, third paragraph, of the DEIR is hereby amended as follows:

PG&E has taken steps to ensure that the new owner will be the holder of the CESA MOU and the Section 10 Permits at the closing of the sale of the Pittsburg and Contra Costa Power Plants. The CESA MOU includes provision for transfer of the CESA MOU to the new owner. NMFS and USFWS have agreed to work with PG&E and the new owner to reissue the Section 10 Permits to the new owner on an expedited basis. In addition, the draft Implementing Agreement outlines the process proposed by NMFS legal counsel for the reissuance of the Section 10 Permits ~~and transfer of the draft~~ , including the related Implementing ~~agreement~~ Agreement and HCP ~~to the new owner~~. Section 13 currently provides that upon the new owner satisfying specified conditions, the federal agencies will use their best efforts to issue new permits within 60 days of receipt of a complete application for permit reissuance. ~~USFWS has proposed revisions to the language drafted by NMFS, and therefore the language of Section 13 is still subject to change. Nevertheless, USFWS legal counsel has indicated to PG&E that a reissuance of the Section 10 Permits to the new owner can be accomplished within a 60-day period~~The USFWS has concurred with this expedited timeline. Accordingly, if the Section 10 Permits are issued to PG&E and the new owner applies for permit reissuance at least 60 days prior to ~~or at~~ closing, the permits should be reissued to the new owner at closing, and the new owner will be subject to the restrictions of such permits and the CESA MOU ~~upon the closing of the sale~~ to the same extent PG&E would have been.

L28 Please see response to Comment L27.

L29 Please see response to Comment L27.

L30 Page 4.7-36, third paragraph, of the DEIR is hereby amended as follows:

> ~~As a condition of closing the sale~~If the Section 10 Permits have been reissued to PG&E prior to closing, the new owner will be required to ~~obtain~~ seek the reissuance of the Section 10 Permits issued to PG&E, and accept the permittee's obligations under the CESA MOU, the HCP and the Implementing Agreements. If the permits have not been issued to PG&E, the new owner will be required to resubmit and accept any obligations under, PG&E's pending applications for the Section 10 Permits, including the resubmittal of the then-current draft Implementing Agreement and HCP, and will seek to obtain such permits on substantially the same terms and conditions as were contained in PG&E's permit applications.

L31 As the timing requirement associated with Mitigation Measure 4.7-2 is currently written, documentation verifying that plant managers have received copies of the commitments to the pertinent obligations must be submitted to the CPUC at least 40 days before the transfer of title. No change is deemed necessary.

L32 Page 4.7-37, under the heading "Level of Significance after Mitigation," of the DEIR is hereby amended as follows:

> If the Section 10 Permits are not issued to the new owner prior to or at closing, the project may result in an unauthorized taking of listed species. The new owner's commitment to obtain the permits and to comply with the ~~Operational~~ operational ~~Constraints~~ constraints in PG&E's Section 10 Permits and the HCP during the interim period before they are issued will reduce this impact to less than significant.

L33 Page 4.9-4 of the DEIR (last sentence at bottom) is hereby revised as follows:

> With the exception of the sulfuric acid contained in lead-acid batteries, no acutely hazardous materials are used or stored at the Potrero Power Plant.

L34 Page 4.9-5 of the DEIR (last sentence at bottom running to top of next page) is hereby revised as follows:

> According to information provided in the study, operations during the site's use as an MPG have ~~adversely~~ impacted the groundwater and soil in areas of the plant. ~~throughout the entire plant area.~~

L35 Pertinent information presented in the Phase II Environmental Site Assessments is summarized in the responses to Comment F33 and Comment T10, and in the staff-initiated text changes in Chapter 4 of this document.

L36 PG&E states that while the appropriate lead agency for cleanup at each plant would be selected by means of the "Site Designation Process Under the Unified Agency Review of

Hazardous Material Release Sites" (as is described on page 4.9-17 of the DEIR), other selection processes might be used to honor arrangements with local agencies that might already be in place.

Page 4.9-17 of the DEIR (paragraph 1, second complete sentence) is hereby revised as follows:

> The appropriate lead agency at each plant will likely be selected by means of the Site Designation Process Under the Unified Agency Review of Hazardous Material Release Sites (California Environmental Protection Agency, 1997).

L37 Page 4.9-19 of the DEIR (second bulleted paragraph, first sentence) is hereby revised as follows:

> Ammonia (typically dissolved in water as NH_4OH) has been ~~is~~ used in the past in emissions abatement equipment, but is no longer used.

The following sentence is added to the end of second bulleted paragraph on page 4.9-19 of the DEIR:

> Ammonia is not currently used in emissions abatement equipment at the power plants to be divested.

L38 Please see response to Comment N51.

L39 Page 4.12-3, sixth paragraph, first sentence, is hereby amended as follows:

> The transmission corridor serves San Francisco and the former Skyline District (in both San Francisco and San Mateo ~~County~~ Counties) loads (i.e., the aggregate demand for electricity from inhabitants of these areas) and is rated about ~~730~~ 750 MW.

L40 Page 4.12-5, last paragraph, first sentence, is hereby amended to read:

> …San Mateo Substation are automatically opened at the Martin Substation to ensure service to the network load.~~to protect the in-city on-line generation from potential crippling damage."~~

L41 Page 4.12-7, first full paragraph, first sentence, is hereby amended to read:

> The network load includes City Hall, PG&E headquarters, ~~the CPUC,~~ BART and Municipal transit loads, and many of the skyscrapers of the financial district. Many of these loads cannot be interrupted, even momentarily, without possible significant health and safety impacts (e.g., trapping people in elevators ~~and in BART trains under the bay~~), and too, it may prove a difficult and lengthy task to re-energize this older non-radial network.

L42 The commenter is correct that the percentage of the downtown load required to be served by San Francisco Peninsula generation varies with load. Also, the smaller amount of Peninsula generation required to be on line during the off-peak period will support some of the downtown load.

The second sentence in the third full paragraph on page 4.12-7 of the DEIR is hereby amended as follows:

> The SFOC require the System Dispatcher to load the San Francisco generation at the Potrero and Hunters Point Power Plants to supply a significant share (the exact percentage varies with demand) ~~40 percent~~ (PG&E, 1994) of the San Francisco load during all peak and partial peak hours.

The fifth sentence in the third full paragraph on page 4.12-7 of the DEIR is hereby amended as follows:

> During off-peak periods, the SFOC ~~is not intended to sustain even the much-reduced downtown loads~~ dictates that about 80 MW of Peninsula generation must be online and dispatched. In case of a disturbance, this dispatched generation would serve to instantaneously support a portion of the downtown load.

L43 The commenter seeks to clarify the point that in fact there are multiple lines between San Francisco and the outside power grid versus a single line. The commenter is correct that there are multiple transmissions lines providing power to San Francisco. While the DEIR text mentioned a single interconnection which, in actuality, contains multiple lines, it is also true that this single interconnection is San Francisco's only electric link to the outside grid. However, in the interest of clarity, page 4.12-9 of the DEIR, first full sentence, is hereby amended to read:

> Additionally, without in-city generation, given the transmission configuration, there would be a citywide blackout if and when the ~~single~~ interconnection between San Francisco and the outside power transmission grid were lost.

L44 Page 4.12-9, last paragraph, first sentence, is hereby amended to read:

> PG&E has just completed installation of shunt capacitors at the Metcalf Substation near south San Jose and during June 1998, and began replacement of two, approximately ~~100~~ 120 MVA (MegaVolt-Amperes) 230 to 115 kV transformers with two 420 MVA transformers at the San Mateo Substation ~~and replacement of 430 MVA transformers~~.

L45 The commenter is correct that the text on Page 5-11, paragraph 2 overstates PG&E involvement in the Santa Rosa Wastewater Modified Geysers Recharge Project. Page 5-11, the first full paragraph is hereby amended to delete the first two sentences as follows:

~~PG&E is one of the key players in the Santa Rosa Wastewater Modified Geysers Recharge Project. However, it is assumed that if PG&E were to sell its units, the new owners would simply assume PG&E's role in the process.~~ The potential increase in steam production…

L46 Please see responses to Comments L4 through L7.

L47 The commenter is correct that the conclusions of Attachment C "further the conservative nature of the analyses" in the EIR. All statements in Attachment C have been checked to the extent possible for accuracy and to minimize any speculation. As with other portions of the EIR, where judgements needed to be made concerning the future behavior of PG&E and of new owners of the plants proposed for sale, the EIR preparers chose assumptions that would avoid any potential for underestimating the changes effected by divestiture and their corollary environmental impacts.

L48 Please see response to Comment L16.

L49 Comment noted.

September 15, 1998

Mr. Bruce Kaneshiro, Project Manager
c/o Environmental Science Associates
225 Bush Street, Suite 1700
San Francisco, CA 94104

Subject: Public Comment on Draft Environmental Impact Report (EIR) for California Public Utilities Commission Proceeding No. 98-01-008

Dear Mr. Kaneshiro:

[Begin M1]
Pages S-16 and 6-28 of the draft EIR state that a combination of Alternative 2A, the bundling of Potrero, Contra Costa and Pittsburg and Alternative 3, the sale of the Geysers plant to the steam field operators is the "environmentally superior alternative". The logic for selection of this alternative as superior seems to be based on the EIR author's assumption that, if one company owned all three fossil fueled power plants, the company would not operate the plants at their maximum generating capacity. The assumption on which the alternative selection has been made would appear to conflict with the most basic precept of free enterprise: obtaining maximum profit from investments. The plants will be operated according to market demand, not according to plant ownership.

The conclusion in the EIR that it is unnecessary to scientifically model the project as proposed by PG&E (to sell the plants in four packages: Pittsburg and Contra Costa together, Potrero separately, the Sonoma Geysers units and the Lake County Geysers units) seem to conflict with the recommendation of an alternative to the proposed project formulated on the basis of a dubious market assumption. ARCADIS Geraghty & Miller, Inc. recommends that this conflicting language in the Draft EIR be rectified before issuance of the final EIR. If the Public Utilities Commission allows PG&E to proceed with the sale as proposed, while the EIR appears to recommend a different approach, the ambiguity may cause some consternation among the public. We recommend the Draft EIR be amended to delete the reference to the "environmentally superior alternative" because there is no empirical evidence to support selection of that alternative and the statement itself is misleading.
[End M1]

Sincerely,

/s/

Donald M. McArthur
Associate, Officer Manager

COMPANIES

M. ARCADIS GERAGHTY & MILLER

M1 The choice of Alternative 2A in combination with Alternative Three as the "environmentally superior" alternative was based on factors not necessarily reflected in the modeling results. In each divestiture scenario analyzed, the same assumption was used that the new owners could run the fossil-fueled plants up to their Analytical Maximum. Alternative 2A, selling the plants as a bundle, does not change this assumption, but it does lessen to some unquantified degree the tendency of new owners to operate more than PG&E would if it retained the plants. Alternative 3 was chosen for the Geysers because integration of the plants with the steam suppliers is likely to lead to more efficient and greater use of the available steam resource, as well as coordination between the steam fields and the generating units. This difference does show up in the model outputs when comparing this scenario (Table G-7) to the baseline (Table G-1). (The decrease in Geysers generation shown in Table G-5 is an anomaly caused by divestiture of the fossil-fueled plants, and not divestiture of the Geysers plants. Please see response to Comment H18.)

The project as proposed by PG&E (selling the plants in four packages) was indeed modeled. The Analytical Maximum capacity factors of the plants sold in the packages proposed by PG&E form the basis for the environmental analysis in the EIR.

The designation in the DEIR of an "environmentally superior alternative" is a requirement of CEQA and, therefore, this cannot be removed. However, the CPUC is not obligated to select the "environmentally superior alternative."

September 16, 1998

Mr. Bruce Kaneshiro, Project Manager
C/o Environmental Science Associates
225 Bush Street, Suite 1700
San Francisco, CA 94104

RE: Written Comments on the Draft EIR for Application No. 98-01-008

Dear Mr. Kaneshiro:

[Begin N1]
Please accept the attached written comments submitted by Calpine Corporation on the above draft EIR. We hope that ESA will find our comments environmentally relevant and thus address them in the final EIR. We are especially concerned that the Cumulative Impacts Analysis be modified to more accurately reflect how output projections will vary under the ownership Scenarios 1 and 3. We believe that Geysers' plant outputs have been optimistically projected (in an ambiguous fashion) in the supporting tables and would urge that ESA concentrate their efforts on adjusting those projections in a more realistic, understandable fashion.
[End N1]

Thank you for the opportunity to comment.

Sincerely,

/s/

J.M. Rudisill
Vice President – Geothermal Operations

cc w/attach: C.L. Wardlow
J.E. Ronan, Jr. Esq.
E. Ko, Esq.
L.R. Krumland
R. Zahner
D.J. Gilles

Calpine Corporation's
Comments on
CPUC PG&E Power Plant Sale Draft Environmental Impact Report, 8/98
Compiled by Jacob M. Rudisill and Charlene Wardlow

Significant EIR Issues

Issue	EIR Location	Comments
1. Santa Rosa Reclaimed Water--Geysers Recharge Project.	**Page 5-10, 5-11 & 6-24** "PG&E is one of the key players in the Santa Rosa Wastewater Modified Geysers Recharge Project." **Page 6-24** "...steam field operators and PG&E have entered into an agreement to inject..." **Page 5-11** "...existing units could be operated at sustained power generation rates for 20 to 30 years."	[Begin N2] PG&E is not a "key player" in Santa Rosa Reclaimed Water Project. They are not involved in the project and there will be no role for a new owner to assume in the process. [End N2] [Begin N3] No such agreement or commitment of Santa Rosa water to PG&E's plant area exists (for the Santa Rosa project). [End N3] [Begin N4] Field capacity of 700 MWs is assumed to be sustainable for 25 years. This unsupported assumption is contrary to the field decline data shown in Table C-1. The assertion is not supported by any analysis or reference. [End N4]
2. Generation Forecast	**Page C-9, Tables C-1, S.1, S.3, 5.2, 6.1.** Generation from the Sonoma County units increases 4 MW from 1999 to 2005 while they operate at maximum base load output. The Lake County units decline only 8 MW.	[Begin N5] This claim that the field will undergo a dramatic reversal of its historic performance trends is unsupported by any assumption in the document. PG&E's estimates of hypothetical available generation in years of heavy curtailment appear to have been extrapolated without regard for the actual operating conditions of the forecast period.

3. Confusion over capacity factors.	**Table S.3 and Footnotes, Tables 5.2, 6.1, C-1**	We recommend that actual megawatt-hours be projected instead of percentages. The interchanging use of 'net generating capacity' for design capacity and net output throughout the draft EIR is confusing. [End N5] [Begin N6] The term "Capacity Factor" is used to refer to ratios with different bases within the same table, and which are inconsistent with conventional terminology as used in Table 2.1. It is unclear whether one of the "Capacity Factor" used is the same as the "Adjusted Capacity Factor" used by PG&E in its CPUC filings. The text and table should either avoid using ratios ("Factors") and simply state values in Megawatt hours or annual average power output (in mw). Additionally, adequate definitions and explanations should be provided. The draft document is ambiguous in the analysis of production. [End N6]
4. Cumulative Impacts – Energy and Mineral Resources	**Table S.4**	[Begin N7] Benefit is claimed for the proposed project that actually occurs only under Alternative 3. The Executive Summary should already state that ownership by the Steam Supplier provide environmental benefit. [End N7]
5. NEC ownership.	**Page 6-23**	[Begin N8] NEC is not a Japanese turbine producer, but a geothermal steam production company. [End N8]
6. "Increased electrical demand" leading to increased Geysers output.	Overhead presented in Cobb and Santa Rosa.	[Begin N9] The Geysers is a declining resources. It is not logical that increased electrical demand will have any bearing on The Geysers' output. [End N9]

7. Steam stacking and "puff" definitions	**Pages S-16, 1-7, 4.5-47; 4.5-75, Page 6-24 (steam stacking)** **Page 6-23, 6.4.3, 2nd paragraph (puff)**	[Begin N10] Steam stacking is "the controlled release of unabated geothermal steam." This activity is conducted in accordance with local Air Pollution Control District regulations. The technical discussion of the puff is incorrect. [End N10]
8. Noise level increase for alternative 3.	**Page S-24, 4.10-2 Alternative 3.**	[Begin N11] Please explain how the noise level will be greater under Alternative 3 – Geysers than under the proposed project. [End N11]
9. "Wasted resource" if plant capacity factor is lower.	**Page S-22, Impact 4.8-2, Page 4.8-4 Impact 4.8-2**	[Begin N12] If the new owner operates the power plant in a manner similar to PG&E's operations (Page S-6), the project would promote wasteful and inefficient use of a valuable natural resource. [End N12]
10. The phrase "reasonably foreseeable" could be misleading	**Page S-6**	[Begin N13] The steam sales agreements between PG&E and each of Unocal, NEC, and Thermal are long term legal obligations which will bind the permitted successors and assigns of the parties. [End N13]
11. Power plant cooling tower drift impact at Geysers.	**Pages 4.5-15 & 4.9-13 (Potential Site Contamination 1st Paragraph, last sentence.)**	[Begin N14] FTP is discussed but not Geysers cooling tower drift impacts inside and outside of power plant yard. Cooling tower drift is an ongoing issue and has been extensively studies by PG&E (including the Phase 1 Environmental Site Assessment). What are impacts outside of power plant yard? This could be important to new owners in regard to remediation and liability issues. [End N14]

General Comments

[Begin N15]
- Review focus on accuracy and environmental remediation issues (for due diligence efforts).

[End N15]

[Begin N16]
- General comment throughout -- refer to condensate as steam condensate [End N16]

Page S-21

[Begin N17] Typos, font of 4.6-4. [End N17]

Page 1-7

[Begin N18] Item 1 The statement that Geysers power production becoming non-economic may lead to shutdowns and thus stacking is unsupported. [End N18]

[Begin N19] Item 4; The assertion that increased stream water diversion will occur if sales are unsupported. [End N19]

Page 2-28

[Begin N20] GEO should be GEP. [End N20]

[Begin N21] SMUD is now Sonoma>>>>change throughout EIR [End N21]

[Begin N22] Santa Fe is now Silverado/Calistoga [End N22]

Page 2-35

[Begin N23] Geysers Geothermal Field – What is the "Geysers Geothermal Area" Isn't The Geysers Known Geothermal Resource Area what is really meant? And it is much larger than 5.5 miles by 1 mile. Big Sulphur Creek or Big Sulfur Creek [End N23]

Page 2-36

[Begin N24] 3rd full paragraph, last sentence--add "a conceptual diagram of' after and before "the circulation." [End N24]

[Begin N25] 4th paragraph, 5th sentence—Southeast Geysers Effluent Pipeline is operating; Santa Rosa Wastewater is a project which the City of Santa Rosa has adopted but it still faces legal challenges and it is undergoing design engineering and funding efforts. [End N25]

[Begin N26] Strike "evaluated as a viable" and replace with "used as a" [End N26]

Page 2-38

[Begin N27] 1st full paragraph, first sentence -- remove "purified", "pressurized." Add "to power plants" after "insulated pipes." [End N27]

Page 2-39

[Begin N28] 1st paragraph, 2nd sentence -- steam condensate has been injected since 1968. [End N28]

[Begin N29] Strike "is believed to"; add s to "increase": strike "to" and add "s" to "increase. [End N29]

[Begin N30] 3rd sentence—strike "it is expected that" [End N30

[Begin N31] 2nd paragraph, first sentence, last word -- change "agencies" to "steamfield operators". [End N31]

Page 2-42

[Begin N32] Top of page -- add "Lake County" before "area." [End N32]

[Begin N33] Table 2-3 -- add Lake County under local and elsewhere. [End N33]

Page 4.1-1

[Begin N34] 4th paragraph, first sentence -- change "Geysers" to "thermal features." [End N34]

Page 4.1-15

[Begin N35] Under Geysers Power Plant -- change "10" to "30." [End N35]

Page 4.3-4

[Begin N36] 2nd paragraph, 2nd sentence – change "steam generating conditions" to "production intervals"? [End N36]

Page 4.3-12

[Begin N37] Impact 4.3.3, paragraph 2 -- suggest rewriting entire, unclear paragraph. [End N37]

Page 4.4-10

[Begin N38] Geysers Power Plant, 1st paragraph – what about Cobb, Anderson, other creeks (See 4.4-6.)? [End N38]

[Begin N39] 2nd sentence and Table 4.4-2 -- Units 7-10, 12, 13, 16, 20 are also close to streams. [End N39]

Page 4.4-13

[Begin N40] 4th paragraph -- DOGGR regulates Class V injection, NCRWQCB also reviews injection "permits." Class V UIC program is permit by rule. No actual "permits" are issued. [End N40]

Page 4.5-47

[Begin N41] 2nd paragraph -- rewrite stacking description. Add "controlled" after "scheduled" in last sentence. [End N41]

[Begin N42] 3rd paragraph, 3rd sentence -- replace "relieving" with "lowering." [End N42]

[Begin N43] Last paragraph -- what about H_2S? [End N43]

Page 4.5-49

[Begin N44] Do PM-10 #s assume all TSPs are PM-10? [End N44]

Page 4.8-2

[Begin N45] 3rd para. –Lake county units do not have untreated sanitary effluent from the plants injected into the steam field. [End N45]

Page 4.9-14

[Begin N46] Impact 4.9-1 -- what is the reasoning supporting the 1st sentence ("divestiture will promote accelerated environmental cleanup....")? [End N46]

Page 4.9-19

[Begin N47] Add sodium vanadate and hydrogen to list [End N47]

Page 4.9-22

[Begin N48] Impact 4.9-4, 1st paragraph, last sentence -- add "hydrogen." [End N48]

Page 4.11-8

[Begin N49] 1st paragraph – Unocal responds to incipient fires only. [End N49]

Page 4.11-12

[Begin N50] Police, 2nd sentence -- change to "remote location and restricted access." [End N50]

Page 4.11-16

[Begin N51] Geysers Power Plant, 1st sentence -- $920,000 million? Or $920,000? [End N51]

Page 4.12-14

[Begin N52] GPP description not accurate re: Lake county units. [End N52]

Page 4.14-5

[Begin N53] Geysers Power Plant -- Strike "about 1971" to "1960" [End N53]

Page 5-8

[Begin N54] Last bullet -- "and" should be "an." [End N54]

Page 5-23

[Begin N55] Basin 2000 and 70 acre parcel are Lake County projects. Why do these projects require Sonoma County Community Development Commission review? [End N55]

Page 5-27

[Begin N56] 2nd paragraph, 2nd sentence -- change condensation to steam condensate. [End N56]

Page 5-32

[Begin N57] Geysers Power Plant, 2nd Paragraph -- two periods at end of 2nd sentence. [End N57]

Page 6-11

[Begin N58] Geologic Problems, 2nd Paragraph -- PG&E is not currently involved with seismic monitoring. [End N58]

Page 6-24

[Begin N59] The flow is 8 mgd, not 6. [End N59]

Page 6-26

[Begin N60] 1st Paragraph, 1st sentence -- why would "risk of an upset condition" increase? [End N60]

Page C-7

[Begin N61] 1st paragraph, 7th sentence change "pump" to "pipe", and 200 to 130. [End N61]

[Begin N62] 4th paragraph, 2nd sentence change "pressure" to "production" [End N62]

Page C-8

[Begin N63] Bullet 4; Change verbs to "collect" and "direct" [End N63]

Page C-9

[Begin N64] 1st sentence "injections" should be "injection" [End N64]

[Begin N65] 3rd paragraph 5th sentence -- There is no substantiation to the statement that operational changes have affected "actual geology" of the KGRA. [End N65]

Page C-21

[Begin N66] Under Geothermal Plant, Unocal is no longer involved with refining and retailing. [End N66]

Page C-33

[Begin N67] Footnote 63 Although technically the UNT/PG&E contract does allow the sale of steam to others, such sale can be performed only after a succession of tests and declaration by each party which severely hinders the ability of the steam supplier to sell to others. [End N67]

[Begin N68] Footnote 65 Add Unit 15. [End N68]

N. CALPINE

N1 Please see responses to Comments H18 and N5.

N2 Please see response to Comment L45.

N3 The reference is to both the Lake County and Santa Rosa effluent pipeline projects. PG&E is a signatory to the former but not to the latter. However, to avoid confusion, the first sentence of the first full paragraph of page 6-24 is amended as follows:

> In addition, <u>two projects are either underway or proposed</u> ~~the current steam field operators and PG&E have entered into an agreement~~ to inject effluent…

Page 6-24, second full paragraph, is hereby amended as follows:

> The current steam field operators have a contract to accept <u>effluent from the Lake County Sanitation District effluent injection project</u> ~~this effluent for injection~~ for 25-30 years. <u>Although the Santa Rosa project has been approved by the City of Santa Rosa, neither PG&E nor the steam field operators have entered into agreement to accept the effluent water at this time.</u>

N4 The 700 MW figure cited on page 5-11 of the DEIR (first paragraph, last sentence) is incorrect and inconsistent with Attachment C because it refers to the generating capacity of all 18 Sonoma County generating units at the Geysers, including eight generating units not owned by PG&E, rather than the capacity of the PG&E generating units alone. Accordingly, the last sentence of the first paragraph on page 5-11 of the DEIR is hereby deleted as follows:

> …These projects would decrease the need for low flow operation and early abandonment of units in the Geysers area. ~~For the units currently owned by PG&E, this would mean an assumed sustained power generation of about 700 MW for 25 years.~~

N5 The figures in the tables cited by the commenter reflect the predicted net capacities of the Geysers units over time after the addition of the Santa Rosa wastewater project. Rather than a “dramatic reversal of historic performance trends,” these numbers reflect the one-time addition of 63 MW of generating capacity shortly after the Santa Rosa wastewater project comes on-line, followed by a steady decline in the steam fields, resulting in a net increase of 4 MW in 2005 for the Sonoma County units.

The DEIR analysis did not extrapolate “PG&E’s hypothetical available generation in years of heavy curtailment,” as asserted by the commenter. The amount of available generation at baseload operations in the absence of wastewater injection from either Lake County or Santa Rosa was derived from PG&E’s *Report on Reasonableness of Operations for 1997*, filed in A.97-12-020, at pages 3-21 to 3-23. Available generation for 1998 was drawn from PG&E’s “Amendments to the Must-Run Agreement between PG&E and the ISO and

Schedules for Must-Run Facilities," filed January 29, 1998, Volume 1B, The Geysers Main-Appendix C and the Geysers - 13&16-Appendix C. These two estimates are consistent with each other and imply baseloaded, continuous operation of the Geysers plants. Actual generation was forecasted by the SERASYM™ production costing model taking into account reliability needs and the hourly demand and the marginal cost of various supplies as discussed in Attachment G of the DEIR. The contract price for the U-N-T and Calpine geothermal facilities were assumed to match those currently found in the PG&E power purchase agreements, which escalate in future years.

The *1992* and *1994 CEC Electricity Report* forecasts for Geysers generation were found by analysis to be outdated. Figure N5-1 compares historic actual or available (when curtailed) generation through 1998. It is immediately obvious that the Geysers steam resource is not declining as rapidly as forecast in 1992 and 1994. PG&E's *Report on Reasonableness of Operations for 1997* discusses the many reasons for this dramatic change in the decline. For this reason, a new forecast was developed.

Unfortunately, the key data set necessary to forecast steam field decline—steam field pressure measured at the wellhead—is proprietary information held by the steam field owners (Calpine and U-N-T). While developing this analysis, informal requests for the most recent steam field forecasts were requested from the steam field owners, but the requests were refused. Without this data set, a trend forecast was developed instead to estimate the decline rate in available generation. The equation is shown in footnote 18 on page C-19 of the DEIR. Figure N5-2 compares two trend forecasts to actual and available (when curtailed) generation excluding the two wastewater effluent pipelines.[8] The forecasts fit the historic data extremely well. The first forecast used 1988 to 1994 data, which excluded any curtailments; in other words, this forecast is based solely on continued baseload operations. The second forecast incorporated data through 1997. The forecasts were virtually identical, and the latter was chosen because it was statistically more significant.

The baseline forecast was supplemented by the projected annual impact of the Lake County wastewater disposal system for the 1999 forecast and both the Lake County and Santa Rosa wastewater pipelines for the 2005 cumulative projections. Care was taken to allocate the increase in generation between PG&E and other Geysers geothermal generators and among the several affected PG&E units in the case of the Sonoma County disposal impact. The forecasts assume that the Lake County water disposal increased the PG&E Geysers units potential generating capacity by about 13 MW in 1999 and by about 15 MW in 2005. The Santa Rosa pipeline was assumed to be in operation before 2005 and to increase potential generation among the PG&E units by about 63 MW. This forecast is at the minimum end of the range of possible forecasts for the Santa Rosa pipeline; assumes that all of the generation benefit will accrue to PG&E units consistent with the April 1998

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8 As explained in the DEIR, until 1994 PG&E accepted all available geothermal steam supplies. After 1994, PG&E curtailed steam deliveries, particularly from U-N-T. However, PG&E tracks how much geothermal steam generation would have been available without economic curtailments. This is "available (when curtailed) generation." This latter data is published in the "Reasonableness of Operations" and the ISO RMRA Appendix C.

agreement between U-N-T and Santa Rosa; and nets out 7 MW of pumping load assumed absorbed by the generators to account for the generators' share of wastewater pumping load.

While developing this analysis, informal requests for the most recent steam field forecasts were requested from the steam field operators, but the requests were refused. For this reason, the fundamental equation underlying the forecast in Table C-1 is unchanged.

However, the Geysers generation forecasts shown in Table C-1 and Attachment G are inconsistent because new information about the effect of the Santa Rosa effluent pipeline was included in the SERASYM™ modeling, but not in Attachment C. Therefore, Table C-1 on page C-10 of the DEIR is revised as follows:

TABLE C-1
ANNUAL PG&E GEYSERS GEOTHERMAL CAPACITY AND ENERGY

	Available PG&E Generation			**Actual PG&E Generation**	
Year	**MW**	**GWh**	**CF**	**GWh**	**CF**
1988	1,199	9,203	87.6%	9,203	87.6%
1989	1,079	8,053	85.2%	8,053	85.2%
1990	948	7,335	88.3%	7,335	88.3%
1991	902	6,947	87.9%	6,947	87.9%
1992	882	7,007	90.7%	7,007	90.7%
1993	791	6,491	93.7%	6,491	93.7%
1994	761	6,024	90.4%	6,024	90.4%
1995	748	6,080	92.8%	4,002	61.1%
1996	769	5,904	87.6%	4,515	67.0%
1997	712	5,739	92.0%	4,830	77.4%
1998	686	5,607	93.3%		
1999	665 ~~693~~	5,445 ~~5,666~~	93.4%		
2000	652 ~~680~~	5,338 ~~5,565~~	93.4%		
2001	697 ~~669~~	5,703 ~~5,474~~	93.4%		
2002	688 ~~659~~	5,629 ~~5,392~~	93.4%		
2003	679 ~~650~~	5,555 ~~5,316~~	93.4%		
2004	672 ~~641~~	5,498 ~~5,246~~	93.4%		
2005	664 ~~633~~	5,433 ~~5,181~~	93.4%		

FIGURE N5-1
COMPARISON OF PG&E GEYSERS GEOTHERMAL FORECASTS
(CEC Electricity Reports vs. Historic Data)

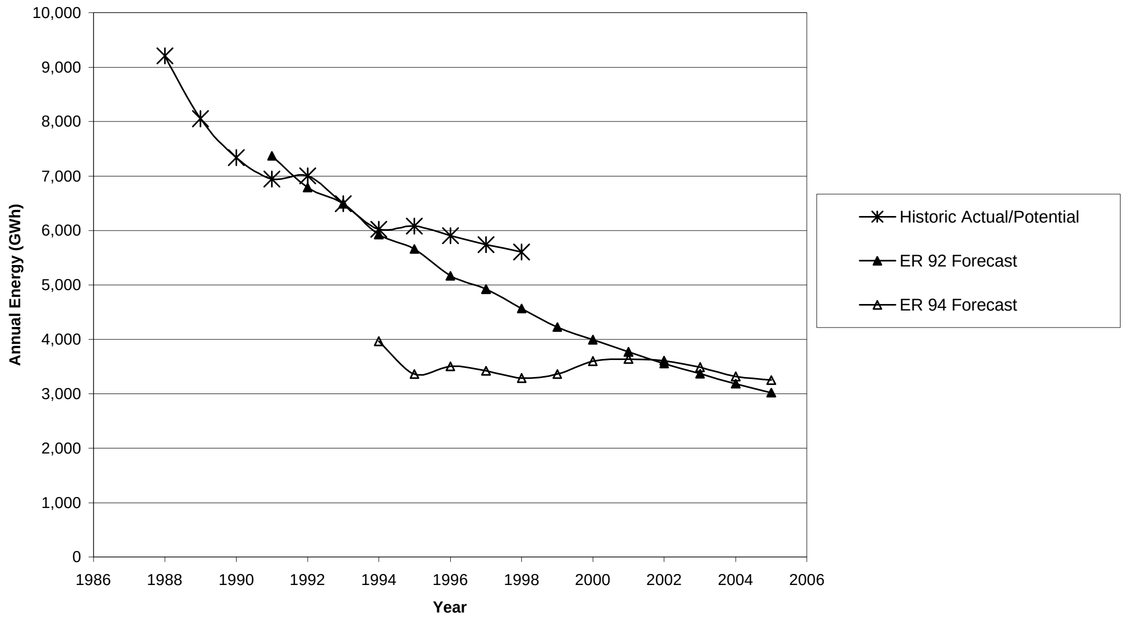
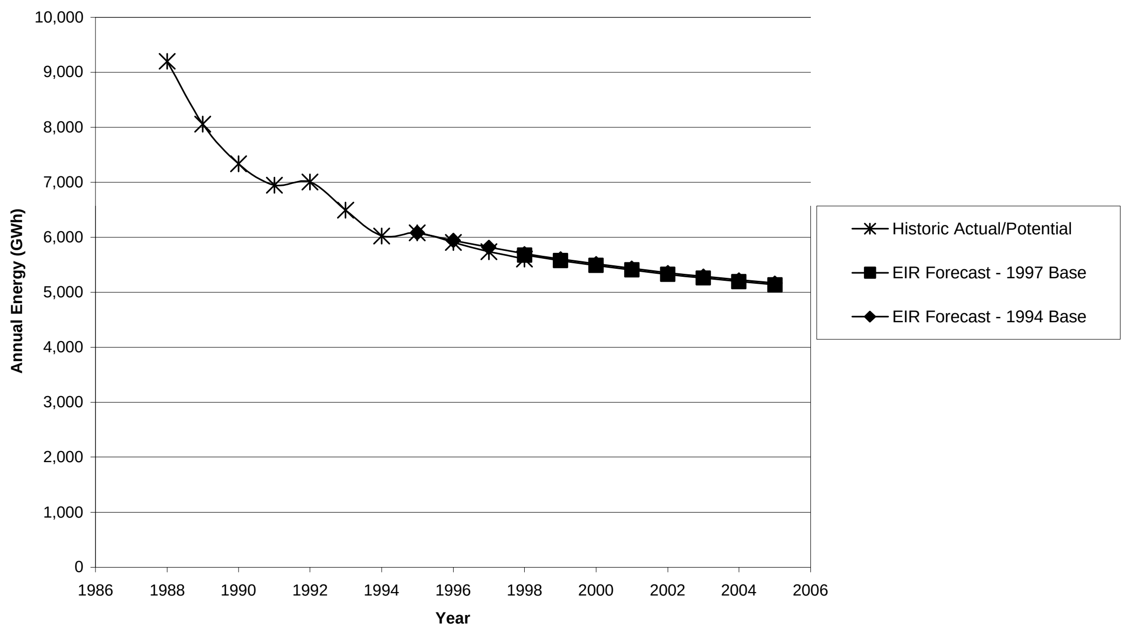


FIGURE N5-2
COMPARISON OF PG&E GEYSERS GEOTHERMAL FORECASTS
(PG&E Divestiture DEIR vs. Historic Data)



Addressing the commenter's recommendation to use megawatt-hours instead of percentages, please see the response to Comment N6.

N6 Because capacity factors are the common measure used for all the divested plants, and because using megawatt-hours would simply add an extraneous calculation for those reading the document, capacity factors will continue to be used throughout the EIR. The commenter is correct, however, that the exact nature of the capacity factors listed in the tables cited is unclear. For clarification, capacity factor is defined as the ratio of power (or generation) actually produced by a generating unit to the maximum power (or generation) it could possibly produce in the same time period. For the four Bay Area fossil-fueled power plants, the term "net capacity" is understood to mean the total amount of power the plants could possibly deliver into the transmission grid, which equals the design or nameplate capacity minus the amount of power consumed by loads within the power plant, such as feed pumps, and electric losses, such as transformer losses. For the Geysers Power Plant, "net capacity" is also understood to mean the total amount of power that the plant could deliver into the transmission grid, but in addition to adjusting the nameplate capacity for in-house loads and losses, the "net capacity" for the Geysers generating units also accounts for the declining capacity of the steam fields that feed the generating units. To better clarify the use of capacity factors for comparative purposes, the following revisions are made in the DEIR:

At page S-10, Table S.1, note (a) is revised as follows:

> 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~~ <u>is defined as the ratio of power (or generation) actually produced by a generating unit to the maximum power (or generation) it could possibly produce in the same time period.</u>

Table S.1, note (b), is revised as follows:

> <u>For the four Bay Area fossil-fueled power plants, the term "net capacity" is understood to mean the total amount of power the plants could possibly deliver into the transmission grid, which equals the design or nameplate capacity minus electric losses and the amount of power consumed by loads within the power plant.</u> 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.
>
> <u>For the Geysers Power Plant, "net capacity" is also understood to mean the total amount of power that the plant could deliver into the transmission grid, but in addition to adjusting the nameplate capacity for in-house loads and losses, the "net capacity" for the Geysers generating units also accounts for the change over time in the capacity of the steam fields that feed the generating units.</u> The net <u>design or</u>

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

Table S.1, note (e), is revised as follows:

Net available rated capacity for the entire plant in the specified year.

At page S-14, Table S.3, note (a) is revised as follows:

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~~ is defined as the ratio of power (or generation) actually produced by a generating unit to the maximum power (or generation) it could possibly produce in the same time period.

Table S.3, note (b), is revised as follows:

For the four Bay Area fossil-fueled power plants, the term "net capacity" is understood to mean the total amount of power the plants could possibly deliver into the transmission grid, which equals the design or nameplate capacity minus electric losses and the amount of power consumed by loads within the power plant. 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.

For the Geysers Power Plant, "net capacity" is also understood to mean the total amount of power that the plant could deliver into the transmission grid, but in addition to adjusting the nameplate capacity for in-house loads and losses, the "net capacity" for the Geysers generating units also accounts for the change over time in the capacity of the steam fields that feed the generating units. The net design or nameplate capacity of the Geysers Power Plant is actually 1,224 MW (see Table 2.1 in Chapter 2, Project Description). The net capacities shown here for the Geysers plant are the predicted available rated capacities for the plant based on projected steam availability in 1999 and 2005, respectively.

Table S.3, note (g), is revised as follows:

Net available rated capacity for the entire plant in the specified year.

At page 5-18, Table 5.2, note (a) is revised as follows:

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~~ is defined as the ratio of power (or generation) actually produced by a generating unit to the maximum power (or generation) it could possibly produce in the same time period.

Table 5.2, note (b), is revised as follows:

For the four Bay Area fossil-fueled power plants, the term "net capacity" is understood to mean the total amount of power the plants could possibly deliver into the transmission grid, which equals the design or nameplate capacity minus electric losses and the amount of power consumed by loads within the power plant. 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.

For the Geysers Power Plant, "net capacity" is also understood to mean the total amount of power that the plant could deliver into the transmission grid, but in addition to adjusting the nameplate capacity for in-house loads and losses, the "net capacity" for the Geysers generating units also accounts for the change over time in the capacity of the steam fields that feed the generating units. The net design or nameplate capacity of the Geysers Power Plant is actually 1,224 MW (see Table 2.1 in Chapter 2, Project Description). The net capacities shown here for the Geysers plant are the predicted available rated capacities for the plant based on projected steam availability in 1999 and 2005, respectively.

Table 5.2, note (g), is revised as follows:

Net available rated capacity for the entire plant in the specified year.

At page 6-8, Table 6.1, note (a) is revised as follows:

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~~ is defined as the ratio of power (or generation) actually produced by a generating unit to the maximum power (or generation) it could possibly produce in the same time period.

Table 6.1, note (b), is revised as follows:

For the four Bay Area fossil-fueled power plants, the term "net capacity" is understood to mean the total amount of power the plants could possibly deliver into the transmission grid, which equals the design or nameplate capacity minus electric losses and the amount of power consumed by loads within the power plant. 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.

For the Geysers Power Plant, "net capacity" is also understood to mean the total amount of power that the plant could deliver into the transmission grid, but in addition to adjusting the nameplate capacity for in-house loads and losses, the "net capacity" for the Geysers generating units also accounts for the change over time in the capacity of the steam fields that feed the generating units. The net design or nameplate capacity of the Geysers Power Plant is actually 1,224 MW (see Table 2.1 in Chapter 2, Project Description). The net capacities shown here for the Geysers plant are the predicted available rated capacities for the plant based on projected steam availability in 1999 and 2005, respectively.

Table 6.1, note (d), is revised as follows:

Net available rated capacity for the entire plant in the specified year.

At page C-10, Table C-1, the following text is hereby added as a note to the table:

Capacity factor is defined as the ratio of power (or generation) actually produced by a generating unit to the maximum power (or generation) it could possibly produce in the same time period. The available rated capacity and potential maximum generation at the Geysers generating units changes over time as the capacity of the steam fields changes, while the nameplate or design capacity stays constant at 1,224 MW.

N7 Table S.4 assesses potential cumulative impacts when considering the potential impact of the project together with the potential impact of other local projects. A beneficial impact at the Geysers is claimed because of the potential beneficial impact of local projects--specifically the Santa Rosa Wastewater Injection project, which would help sustain the viability of the Sonoma County steam field. This beneficial impact would occur whether or not the Geysers generating units are purchased by the steam field owners.

N8 Page 6-23 of the DEIR (first paragraph under Section 6.4.3, third sentence) is hereby amended as follows:

Unocal, NEC ~~(a Japanese turbine producer)~~, and Thermal Power Company (a subsidiary of Calpine) operate as an undivided partnership, called UNT, to supply steam to PG&E's Sonoma County units.

Page C-21 (last paragraph, fifth sentence) is revised to read:

NEC ~~is a Japanese turbine producer that~~ has manufactured...

N9 The Geysers has been experiencing economic curtailments by PG&E because the market price has been insufficient to make Geysers generation economically attractive during some periods. Increased demand translates directly into increased market prices, which in turn reduces the amount of economic curtailment at the Geysers. Thus, generation would increase despite the fact that the resource is declining overall.

N10 The Final EIR will be corrected to change the definitions of "steam field stacking" on pages S-16, 1-7, 4.5-47, 4.5-75 and 6-24, and of "puff" on page 6-23.

The third sentence of the paragraph after the "Alternative 3" heading on page S-16 is corrected as follows:

> Steam stacking, which is the controlled release of unabated steam, is caused by the build-up of steam pressure ~~in the pipelines~~ under the wellhead when power plants are idled for maintenance or other reasons.

The first sentence of the first full, numbered paragraph on page 1-7 is corrected as follows:

> (1) The potential for "steam stacking" in the Geysers Geothermal Area. Any reductions in the operation of units at the Geysers Power Plant resulting from divestiture could result in controlled releases of unabated steam ~~releases through unabated steam vents~~.

The first full paragraph on page 4.5-47 is corrected as follows:

> In terms of quantities, the major emissions from the plant consist of total organic gases (primarily methane), particulate matter (including PM-10 and PM-2.5), H_2S, ammonia, and hydrogen. "Permitted" emissions levels relate to particulate matter and H_2S. H_2S emissions can occur as a result of steam stacking, which is the term used to describe the controlled release of unabated steam in order to relieve a buildup of steam pressure in a geothermal field due to a temporary slowdown in use of the steam wells. ~~The steam buildup may result in an unscheduled release of steam from the field to release the excess pressure.~~

The fourth sentence of the paragraph under "Geysers Power Plant" on page 4.5-75 is corrected to read:

> This is because the peaks in hydrogen sulfide concentrations (and ensuing complaints) that have occurred in the past have been the result of ~~uncontrolled~~ controlled releases of steam due to events like steam stacking rather than from the steady-state~~, "controlled"~~ emissions released at the power plants.

The fourth sentence of the second paragraph of Section 6.4.3 (Page 6-23) is corrected as follows:

> If the steam from the steam fields is not used continuously (i.e., when generating units are not operated consistently or at sufficiently high levels), pressure could rise

> to the point that steam stacking (the controlled release ~~build up~~ of unabated steam pressure) can occur ~~in the pipelines~~.

The fifth sentence of the bottom paragraph on page 6-23 is corrected as follows:

> The release of this pressure~~, known as a “puff,”~~ is potentially hazardous both in its intensity and because of its hydrogen sulfide content.

N11 As stated on page 6-27 of the DEIR, under Alternative 3, the level of noise would not be expected to increase, but the frequency of noise events could be increased compared to both the baseline and the project. It is assumed that the plant would continue to operate within established controls of noise.

N12 The impact cited by the commenter on pages S-22 and 4.8-4 of the DEIR relate to wasteful or inefficient use of non-renewable resources. It has no relation to the use of renewable resources, such as geothermal steam at the Geysers. The CEQA Guidelines require a study of a project’s impact on non-renewable resources, such as natural gas, because those resources are finite; once non-renewable resources are depleted, they are gone forever. Conversely, renewable resources are essentially infinite (over time) and cannot be depleted. Though steam pressure and quality have declined at the Geysers steam fields, the heat source creating the steam is essentially infinite, and steam production will continue as long as the fields are recharged through injection and re-injection (though new wells may have to be drilled because of changes in the subterranean geology), which is why all geothermal power resources are classified as renewable under all applicable federal and state laws. Therefore, the commenter’s assertion that PG&E’s present operations result in, or a new owner’s operation would result in, wasteful use of geothermal steam is outside the scope of the EIR.

In addition, the conclusion reached on page 4.8-5 of the DEIR relies on the tenet that “efficient use” of non-renewable resources (e.g., natural gas) could mean increasing near-term generation from the Geysers generating units. For example, increased use of the Geysers might reduce natural gas use at older fossil-fueled plants, thus reducing air pollution and the use of non-renewable resources in the near term. As these older gas plants are retired, newer, cleaner combined-cycle gas-fired plants will come on line. On net, society benefits by having cleaner air on a net present value basis, and by not depleting natural gas stocks as rapidly as might have occurred if Geysers generation was reduced in order to prolong the life of the steam fields.

N13 It is due to these long-term obligations, which as noted would be transferred to the new owners, that it is reasonably foreseeable that a new owner would pay a steam price similar to that currently paid by PG&E and would operate the units in a manner similar to PG&E’s operation. However, it is feasible that market forces, organizational differences, or other unforeseen forces could cause a new owner to operate the plants in a different manner, subject to contractual constraints. For this reason, the phrase “reasonably foreseeable” was used. Please also see the response to Comment P13.

N14 The commenter indicates that FTP is analyzed in the DEIR (beginning on page 4.5-13) but that cooling tower drift at the Geysers is not. It is important to understand that FTP (fallout-type particulate) as discussed in the DEIR is not related to cooling tower drift. Cooling tower drift is a mist or fog that forms in the immediate area surrounding the exhaust stack of a cooling tower and is associated with the cooling tower's exhaust plume. Generally, this mist results in water droplets being deposited on surfaces (i.e., buildings, ground, plants, etc.) downwind of the cooling tower. These water droplets contain dissolved and suspended solids present in the condensed steam that is released through the cooling towers. The solids, or particulate matter, include sulfur compounds, boron, and other compounds that are naturally occurring constituents of the geothermal steam. The horizontal extent of this deposition of these water droplets depends on several factors, including the level of operation of the tower, the humidity and temperature of the ambient air, and the ambient wind speed.

Cooling tower drift affects only the very localized area surrounding the tower, which is typically a zone between one quarter to one half mile. Since the PG&E typical power plant site configuration at the Geysers tends to be fairly small in area, it can be expected that cooling tower drift would be deposited on terrain both inside and outside each unit's fence line. As mentioned on page 4.9-13 in the fifth paragraph, distressed vegetation caused by cooling tower water drift has been observed by Phase I investigators. This distressed vegetation was attributed, by the Phase I investigators, to dissolved boron present in the cooling water being deposited via cooling tower drift and has been noted in the Phase I report at Units 5/6, 7/8, 9/10, 11, 12, 13, 16, 17, 18, 20 and the former Unit 15. No testing has been conducted since the Phase I study was performed (1997) to confirm the cause of damage to vegetation or the presence of boron.

The Permits to Operate issued by the local air districts restrict the emission rate for total suspended particulates (TSP), which include the particulate matter present in cooling tower drift. PG&E monitors and reports the average annual total suspended and dissolved solids present in the cooling tower water to the air districts, which then calculate estimated emission rates. None of the Geysers units in Lake and Sonoma Counties have ever received a citation by the local air districts for particulate emission exceedances.

Potential effects of cooling tower drift will continue regardless of who owns or operates the Geysers Power Plant, and thus would not be affected by the project. Furthermore, short of the units ceasing to operate entirely, these potential impacts occur at most levels of unit operation.

Under the Purchase and Sale Agreement, and as is discussed in response to Comment F41, as well as in the DEIR starting at the bottom of page 4.9-16, PG&E is responsible for remediation of soil and groundwater contamination present at the property before the closing of the sale to the extent required by a regulatory agency with jurisdiction over the site. If it is determined in the future that cooling tower drift resulted in soil or groundwater contamination at the Geysers Power Plant before the closing of the sale, PG&E will be responsible for remediation of such contamination to the same extent as PG&E is responsible for pre-closing soil or groundwater contamination from other causes. PG&E's responsibilities for remediation specifically excludes any obligation to restore or replace vegetation at the site or at any offsite area affected by operations at the site. Therefore, new owners would be responsible for restoring or replacing vegetation at the site or at any offsite area affected by operations at the site that is required after the close of sale.

In addition, if the new owner were to terminate operations at a site, the new owner (rather than PG&E) would be responsible for discharging any obligations imposed by steam purchase agreements, real property agreements, or governmental authorities (including any obligations imposed by the California Energy Commission certifications or use permits) that may require revegetation or restoration of the site to its natural state or original condition.

N15 Comment noted.

N16 In response to comment, text throughout the DEIR relating to "condensate" shall hereby be meant to read "steam condensate."

N17 Comment noted.

N18 The referenced statement in the DEIR is simply a summary of expressed public concerns and does not represent any conclusions made in the EIR. It remains unchanged.

N19 Page 1-7, Item No. 4 of the DEIR lists concerns of the public concerning the project. Although there currently are diversions of some creeks for reinjection, there is no evidence that new owners would attempt additional creek diversions. Diverting surface waters requires approval from the California Department of Water Rights. Concerns about effects on salmonids and the recent listing of steelhead salmon presents very severe limitations on approvals of any potential future diversion. Approval for a major creek diversion by Unocal was denied about ten years ago.

N20 Page 2-28, second complete paragraph, fifth sentence is hereby amended to read:

> …Geothermal Energy Partners (~~GEO~~ <u>GEP</u>)…

N21 Comment noted.

N22 Comment noted.

N23 There is no precise measurement as the boundary of the Known Geothermal Resource Area (KGRA) is irregular. The Geysers Geothermal Field is the central part of a large complex that includes the Clear Lake, Geysers, and Geysers-Calistoga KGRA. The shape of the entire KGRA is irregular but roughly measures 30 miles wide by 50 miles at the longest point. The Geysers itself occupies the central part of the KGRA and measures roughly 3.5 miles wide in the center by 10 miles long.

In order to reflect Calpine's comment for clarification, the first and second line of the third full paragraph on page 2-35 of the DEIR is revised as follows:

> The Geysers Geothermal ~~Area~~ Field, located in the Mayacmas Mountains, is an unusual area of hot springs and steam vents. The area is roughly ~~5.5~~ 10 miles long and ~~1~~ 4 miles wide and is drained by Big Sulphur Creek. The main natural thermal area or reservoir is located along Geyser Creek, a tributary of Big Sulphur ~~Sulfur~~ Creek,…

N24 Page 2-36, third full paragraph, last sentence is hereby amended to read:

> Figure 2.17 shows a conceptual diagram of the circulation of heated underground water at the Geysers Geothermal Area.

N25 Page 2-42, third paragraph is hereby revised as follows:

> The City of Santa Rosa is considering a similar wastewater injection project that could provide an additional 80 to 100 MW of generating capacity at the plant. The Environmental Impact Report (EIR) for this project was certified by the City on January 22, 1998. ~~April 20, 1998.~~ An Environmental Impact Statement (EIS) under the National Environmental Policy Act has also been completed, however, the Record of Decision (ROD) has not been issued pending the application and approval of permits from the Corps of Engineers ~~National Environmental Policy Act review for this project is currently in progress~~. (See Chapter 5, Cumulative Impacts, for a more detailed discussion of this project.). The City is proceeding with engineering design of the project to support the permit applications (Carlson, 1998).

The following reference is hereby added to page 2-46 of the Project Description:

> Carlson, Dan, Engineer, City of Santa Rosa, personal communication, November 4, 1998

N26 Page 2-38, first complete sentence, is hereby amended to read:

> Also, wastewater injection is being used as a ~~evaluated as a viable~~ means of recharging fluids to the steam field…

N27 Page 2-38, first full paragraph, first sentence, is hereby amended to read:

> Generally speaking, steam is drawn from wells~~, purified,~~ transported through insulated pipes~~,~~ to power plants~~, pressurized,~~ and converted into electrical power.

N28 Page 2-39, first paragraph, second sentence is amended to read:

Since 1968~~Currently, the~~ condensate from PG&E's Geysers Power Plant ~~is~~ has been returned to the steam suppliers (i.e., Unocal-Thermal and Calpine) for reinjection into the steam field.

N29 Page 2-39, first paragraph, first sentence is amended to read:

The injection of water (either condensate from the electric power generation process or water from other sources) into injection wells in the steam fields ~~is believed to~~ increases the amount of recoverable steam pressure and ~~to~~ increases the reliability of steam delivery.

N30 Page 2-39, first paragraph, third sentence is amended to read:

In addition, ~~it is expected that~~ the recently initiated…

N31 Page 2-39, second paragraph, first sentence, is hereby amended to read:

…to supply this wastewater to the steam fields controlled and maintained by those ~~agencies~~ steam field operators.

N32 Page 2-42, first line, is hereby amended to read:

…development occurs in the Lake County area…

N33 The table presented in the DEIR was reproduced from the PG&E PEA and is, as stated, a partial list. The Lake County units would continue to need a Hazardous Materials Storage Permit and permits for any underground storage tanks.

N34 Please see response to Comment H24.

N35 Page 4.1-15, last sentence, is hereby amended to read:

The Geysers have been in operation for more than ~~ten years~~ 30 years, with many starting up in the 1970s.

N36 Page 4.3-4, second paragraph, second sentence is hereby amended to read:

…generally coincides with zones of intensive hydrothermal alteration of the Franciscan rocks and ~~steam- generating conditions~~ production intervals.

N37 Paragraph 2 of Impact 4.3-3 (Page 4.3-12) is hereby replaced with the following:

Each of the generating units is connected to a system of steam collection that is tied to the production of many wells. As steam pressure declines in any one well in the field, steam is directed to the plant from other production wells to maintain an optimum operating level.

The collection of steam at a well is temporarily shut off when pressure declines below the minimum until the pressure reestablishes itself to the desired operating level, at which time it is opened again to supply steam to the collection system.

The Geysers is a vapor dominated system. When the steam pressure drops and the well is shut off, pressure reestablishes itself by the process of connate or injectate water moving through the fractures and pores of the surrounding reservoir rock. The water is converted into steam by contact with the hot rock. As the amount of steam increases, the steam pressure builds again in the pores and fractures of the reservoir rock. The production wells then draw off the pressurized vapor and convey it to the plant.

Steam generation is related to economic considerations, power demand, contracts between suppliers and plant operators, O&M requirements, operating strategy, environmental controls etc. However, from a geophysical perspective, steam production is limited by the characteristics of the reservoir rock (heat, fracture and porosity, structure, geochemistry, etc.), the availability of water, and the extent of steam field development (number and relative location of production/injection wells). Probably the most limiting consideration is the availability of water. The Geysers steam field has been overdeveloped because steam extraction exceeds the available steam supply. Given the existing infrastructure and the assumption that the operators would want to continue its use to optimum levels, the desired levels of steam production cannot be met largely because sufficient water vapor is no longer generated in the hot rock. While loss of heat in the rock has occurred in some areas and, in some cases, loss of fracture and pore space because of mineralization has reduced production, for the most part these do not seem to be major causes of steam declines.

In the past, the primary source of water has been connate water. Beginning in 1969, operators began to inject water into the reservoir rock to increase the rate of recovery of steam pressure. In some areas of the Geysers, injection derived steam accounts for 28 percent of steam production. The basic assumption underlying the use of injectate (from either power plant condensate, collection of surface water or importation of water such as the Southeast Geysers Effluent Pipeline, discussed below) is that if more water is injected into the reservoir rock at the proper application rates, steam pressure can be reestablished and sustained.

Sufficient injection water is not available from in-situ sources in the Geysers, that is, steam condensate and surface water collected in small basins (the Geysers in fact receives substantial rainfall—in some places over 80 inches/year). Environmental planning and regulatory restrictions in place prevent the further development of local surface water sources for use in injection. Therefore, steam field operators, in conjunction with PG&E and local agencies, have undertaken importation of water,

> which is discussed further below. Importation of those supplies is expected to reestablish steam levels or, at the least, slow the decline in the stream production.

N38 Page 4.4-10 of the DEIR (fourth paragraph, after third sentence) is hereby revised as follows:

> Other important tributaries include Cobb Creek, Anderson Creek, and Bear Canyon Creek.

N39 The following information is hereby added to Table 4.4-2 of the DEIR:

> Units 9,10 Cobb Creek

N40 Page 4.4-13 of the DEIR (fourth paragraph) is hereby revised as follows:

> Groundwater resources at the Geysers are regulated by the California Division of Oil, Gas, and Geothermal Resources (DOGGR) and by Sonoma and Lake Counties. DOGGR first must approve an applicant's project, which may be for one or multiple wells, and issue a project approval letter. Injection wells are regulated by the U.S. EPA, however, DOGGR has a Memorandum of Understanding with the EPA to issue individual well permits, ~~Permits for injection are obtained through DOGGR~~ with appropriate review from the Central Valley and North Coast RWQCB, as appropriate. Additional regulation is provided by the U.S. Bureau of Land Management (BLM), with delegated authority under the Federal Land Policy and Management Act and Geothermal Steam Act. The BLM, under these and other federal laws, is also responsible for protection and management of water resources on BLM lands and may issue injection permits.

N41 Please see response to Comment N10.

N42 Page 4.5-47, second complete paragraph, third sentence is hereby amended as follows:

> By using automatically activated valves, the manifold distributes the steam according to need, thereby ~~relieving~~ lowering pressure in the line.

N43 The incinerator is designed to oxidize hydrogen sulfide to sulfur dioxide, a less toxic substance. The difference in toxicity between the two pollutants can be emphasized by comparing the short-term standards, where the state one hour standard for sulfur dioxide is over eight times greater than the standard for hydrogen sulfide. Sulfur dioxide emissions are usually very small, because only the residual hydrogen sulfide that is not removed by the abatement process is usually incinerated to sulfur dioxide. With respect to atmospheric oxidation of hydrogen sulfide to sulfur dioxide and ultimately to sulfuric acid, the reaction rates are very slow and should not significantly affect sulfur dioxide concentrations near the plants. This is explained further in response to Comment T5b.

N44 The power plants' PM-10 emissions estimates shown in Tables 4.5-21 and 4.5-22 of the DEIR are based on Title V applications. The PM-10 emission factors used in the Title V applications assume that all of the particulate matter emitted from the geothermal plant sources is PM-10. Most of the PM-10 emissions are emitted at the cooling towers.

N45 The following sentence is hereby added to page 4.8-2 of the DEIR (end of third paragraph):

> Lake County units do not have untreated sanitary effluent from the plant injected into the steam field.

N46 Please see the response to Comment F41. The explanation of why divestiture would promote environmental cleanup at the Potrero Power Plant applies to the Geysers Power Plant and to the other plants being divested as well.

N47 Page 4.9-20 of the DEIR (at end of bulleted paragraphs) is hereby supplemented as follows:

- Hydrogen, the lightest element, is a flammable gas. Hydrogen gas is used at power plants to provide a low-friction atmosphere inside the turbines. Hydrogen is nontoxic, except that it would be an asphyxiant within enclosed spaces. Hydrogen is flammable or explosive when mixed with air or oxygen, and is a dangerous fire hazard when exposed to heat or oxidizing agents. It burns cleanly to form water. Although it is non-toxic, the flammable properties of hydrogen make it a dangerous gas that must be handled carefully.

- Sodium vanadate (technically sodium ammonium decavanadate) is used at several Geysers units within their Stretford sulfur abatement systems. Sodium vanadate is stored as a solid in small amounts (approximately 2-3 pounds at each unit), then mixed with other components as needed to make up Stretford sulfur abatement solution. No hazardous vanadate waste is generated. The chemical is listed as an acute and chronic irritant. Irritation would be primarily to the eyes or respiratory tract upon exposure to vanadate dust. Sodium vanadate emits acrid smoke when heated to decomposition.

N48 Page 4.9-22, first paragraph, last sentence is hereby amended to read:

> Compressed gases including hydrogen are also handled at the plants.

N49 Page 4.11-8, first paragraph, first sentence is hereby amended to read:

> Unocal currently maintains a private fire brigade, including one fire engine, for responding to incipient fires ~~emergencies~~ within the Geysers area.

N50 Page 4.11-12, last paragraph, second sentence is hereby changed as follows:

> Currently, the plant does not pose any particular police protection problems, partly due to its remote location ~~which restricts~~ and restricted access.

N51 Page 4.11-16, under Geysers Power Plant, the first sentence is hereby amended to read:

> The Geysers Power Plant generates an estimated $920,000 ~~million~~ per year in property taxes to Lake County…

N52 Page 4.12-14 of the DEIR (fourth paragraph) is hereby amended to read:

> The Geysers is not served by public sanitary and storm sewer collection infrastructure. At the Sonoma County geothermal units, ~~W~~wastewater from the domestic and sanitary uses is discharged to the on-site gray water or septic tank facilities, and then sent to the steam supplier for reinjection to the steam field. Stormwater is captured by the on-site berms located around the units and also reinjected into the steam field. At the Lake County units, gray water is hauled by a septic tank company and disposed of off site.

N53 Page 4.14-5, under Geysers Power Plant, the first sentence is hereby amended to read:

> Commercial operations at the Geysers Power Plant first began in ~~about 1971~~ 1960.

N54 Page 5-8, under the last bullet, is hereby amended to read:

> …a PG&E-funded project that would replace ~~and~~ an existing 230/115 kV transformer…

N55 The referenced discussion contains inadvertent errors and is accordingly modified as noted below. It should be noted that the Santa Rosa Modified Geysers Recharge Project was approved in spring 1998 but is currently under litigation. Construction of the project has been delayed pending the outcome of the litigation.

Page 5-23 of the DEIR (first complete paragraph) is hereby amended as follows:

> The Basin 2000 Project, which would require approval by the U.S. Environmental Protection Agency, is under consideration by the Lake County Sanitation District (LACOSAN). ~~and the~~ The Santa Rosa Modified Geysers Recharge Project ~~are under consideration by the Sonoma County Community Development Commission and will be accepted or rejected based upon their~~ its ~~compliance with local planning and zoning regulations and policies. The Santa Rosa Modified Geysers Recharge Project is also subject to review and approval~~ was approved by the City of Santa Rosa in January 1998. Although two lawsuits challenging the EIR were subsequently filed, one has been settled, and the City believes the other will be settled soon.[9] Construction is expected to begin in 1999 and be completed by 2002. This project also requires U.S. Army Corps of Engineers approval for a Nationwide Permit under Section 404 of the federal Clean Water Act. Any development on the

[9] Dan Carlson, Capital Projects Coordinator, City of Santa Rosa, personal communication, October 30, 1998.

> recently sold 70-acre parcel (shown in Table 5.1) would ~~also~~ be subject to approval by the ~~Sonoma~~ Lake County Community Development ~~Commission~~ Department.

N56 Page 5-27, second paragraph, second sentence is hereby amended as follow:

> ~~Condensation~~ Steam condensate from the generating units would continue to be reinjected…

N57 The second sentence of the second paragraph under Geysers Power Plant, page 5-32, is hereby corrected to have only one period.

N58 Please see response to Comment H11. The last paragraph on page 6-11 is hereby amended by deleting the last sentence as follows:

> However, the impact would be less than significant. ~~PG&E would likely continue its existing involvement in monitoring seismic activity associated with the Geysers' operation.~~

N59 Please see response to Comment P54.

N60 As described in Impact 4.9-4 (page 4.9-22), the Geysers use various hazardous materials for operation and maintenance. The presence and use of these materials pose a risk of upset. An increase in capacity utilization would require additional use of these materials and, therefore, a slightly higher risk of upset.

N61 Page C-7, first paragraph, sixth sentence, is hereby amended to read:

> …and the steam pressure from the field has been dropping for many years, currently to as low as ~~200~~ 130 pounds per square inch (psi) from a peak of 500 psi.

The eighth sentence is hereby amended to read:

> Another key problem is that it is not economical to ~~pump~~ pipe the steam for more than about a mile…

N62 Page C-7, fourth paragraph, second sentence, is hereby amended to read:

> …the average resulting sustained ~~pressure~~ production determines total 'field capacity' for the next six months…

N63 Page C-8, the fourth bullet is hereby amended as follows:

> Most operators now ~~capture~~ collect condensed steam from their wells and ~~pump~~ direct (inject) the water back into the ground to stimulate steam production.

N64 The first line on page C-9 is hereby amended to read:

…hope that the additional injection~~s~~ will boost…

N65 Page C-9, third paragraph, fifth sentence is hereby amended as follows:

> The changes in operations by PG&E and NCPA also have affected both the apparent steam production rate, and the ~~actual geology~~ <u>steam field well pressures</u> ~~of~~ <u>in</u> the KGRA.

N66 Page C-21, last paragraph, fourth sentence is hereby amended to read:

> Unocal is primarily a large oil and gas production~~, refining and retailing~~ company, which also has developed geothermal plants internationally.

N67 Page C-33, footnote 63 is hereby amended to read:

> While the steam suppliers could theoretically sell to NCPA, SMUD or the QFs, at least <u>three</u> ~~two~~ practical matters basically foreclose this option: (1) <u>such sale can be performed only after a succession of tests and declarations by each party, which severely hinders the ability of the steam supplier to sell to others;</u> (2) steam can be moved only a short distance before it loses its effective energy (i.e., a mile or less in most cases); and <u>(3)</u> PG&E's generation capacity dwarfs the capacity owned by all of the other generators combined.

N68 Page C-33, footnote 65 is hereby revised as follows:

> PG&E has already shut down ~~the oldest four~~ <u>five</u> Geysers plants, the Central California Power Agency has shut down the Coldwater Creek plants, and CDWR's Bottlerock plant has never opened.

September 18, 1998

Mr. Bruce Kaneshiro
Project Manager
Environmental Science Associates
225 Bush St.
Suite 1700
San Francisco, CA 94104

Re: Draft PG&E Environmental Impact Report

Dear Mr. Kaneshiro:

On August 5, 1998 Environmental Sciences Associates issued a Draft Environmental Impact Report ("EIR") on the proposed sale by PG&E of certain generating plants. Among the plants to be sold are the Pittsburg and Contra Costa generating facilities in Contra Costa County. In its discussion of cumulative impacts, the EIR references the Pittsburg District Energy Facility ("PDEF"), a proposed merchant generating facility to be located in Pittsburg, California. This submittal addresses assumptions and conclusions that the PDEF considers to be erroneous. PDEF requests that Environmental Sciences Associates review the comments below and revise the Environmental Impact Report to reflect these corrections. Additionally, certain corrections may require additional model runs to support any conclusions that require modeling input.

PDEF respectfully submits the following comments for your review. If you have any questions regarding these comments please do not hesitate to contact a representative of the PDEF.

<u>Section 5.2.2, page 5-5</u>. In the paragraph describing the PDEF, these are two misstatements:

[Begin O1]
The PDEF is <u>not</u> a joint venture between the City of Pittsburg, Enron and USS Posco. Enron is the developer and is solely responsible for licensing, constructing and operating the PDEF. The City of Pittsburg will share in project profits and USS Posco has agreed to purchase steam and electric energy from the PDEF.
[End O1]

[Begin O2]
Although the EIR is correct that the PDEF CEC application was filed on June 15, 1998, the CEC did not "accept" the application until July 29, 1998. The CEC has one year from July 29, 1998 to process the application.
[End O2]

[Begin O3]
Section 5.3.4, page 5-40. The first full paragraph on this page describes PDEF impacts upon water resources in the Bay-Delta. There will be no such impacts as the PDEF will not make any thermal discharges to the Bay-Delta. The PDEF will utilize cooling towers for heat rejection.
[End O3]

[Begin O4]
Section 5.3.4, page 5-41. The EIR makes certain conclusions regarding air quality impacts, apparently drawn from data on Tables G-6 and G-14. Table G-6 does not contain any PDEF data so it is assumed that the IER makes a comparison between operation without the PDEF (Table G-6) and operation with the PDEF (Table G-14). The actual values for PDEF emissions, compared with EIR values, are listed below:

Table G-14	Actual PDEF			
Nox – lb/MWH		.10	.017	
lb/MMbtu		.014	.009	
Sox – lb/MWH		.01	.008	
lb/MMbtu		.001	.001	
PM10 – lb/MWH		.05	.056	
lb/MMbtu		.008	.007	
CO – lb/MWH		.08	.104	
lb/MMbtu		.011	.014	
VOC –	lb/MWH			.033
Lb/Mmbtu			.004	

To the extent that insertion of the above listed values changes the conclusions regarding air quality impacts which are contained in the EIR, PDEF requests that new computer simulations be run to accurately reflect the impacts of the PDEF.
[End O4]

If you should have any questions, please call me at 415-782-7811.

Respectfully,

/s/

Samuel L. When
Director

O. ENRON CAPITAL & TRADE RESOURCES GROUP

O1 To reflect Enron's clarification, page 5-5 of the DEIR (first bullet, first sentence) is hereby amended as follows:

> The Pittsburg District Energy Facility (PDEF) is proposed by Pittsburg District Energy, LLC (a ~~joint venture between the City of Pittsburg, Enron, and USS-Posco Industries~~ subsidiary of Enron Capital and Trade), and would be operated as part of an alliance agreement between Enron and the City of Pittsburg. The agreement is primarily a statement of the two parties' intention to work together.

Page 5-5 of the DEIR (first bullet, fourth sentence) is hereby amended as follows:

> The site is located on the northwest corner of the property owned by USS-Posco Industries, which has agreed to purchase steam and electric energy from the PDEF.

O2 Page 5-5, the second to the last sentence under the first bullet is hereby amended to read:

> The AFC was filed on June 15, 1998, and the CEC accepted the application on July 29, 1998.

O3 Page 5-40 of the DEIR, the first full paragraph is hereby amended as follows:

> Operation of the new plant could adversely affect water resources in the Bay-Delta. Based on the proximity of the plant to the Contra Costa and Pittsburg Power Plants, the new plant could increase the potential for ~~thermal~~ discharge impacts to marine water quality. This would be a potentially significant cumulative impact on water resources. No increase in thermal discharge is anticipated for the PDEF as it will utilize cooling towers for heat rejection of cooling water. However, any water discharges resulting from cooling-tower blowdowns, like those associated with Pittsburg Unit 7, would be subject to permitting. For these reasons, the owner of the new plant would be required to apply for an NPDES permit from the SFRWQCB prior to operation of the plant. In issuing the NDPES permit, which would establish effluent limitations for the proposed plant, the SFRWQCB would consider all of the discharge sources in the Bay-Delta, including the Contra Costa and Pittsburg Power Plants. Therefore, it is anticipated that any significant cumulative impact on water resources with respect to the inclusion of the PDEF could be mitigated to a less-than-significant level.

O4 Using the emissions factors provided by the commenter, the emissions estimates for the PDEF in 2005 have been revised. Taking into account the revised estimates and other corrections, the first paragraph on page 5-41 of the DEIR is hereby revised as follows:

> Emissions estimates have been made for cumulative scenarios with and without the new PDEF. Tables G-6 and G-14, in Attachment G of this EIR, show estimates of criteria air pollutant emissions under the 2005 Cumulative Analytical Maximum

> scenario and the 2005 Variant 2 cumulative scenario, respectively. A comparison of these scenarios shows that at a regional level (which accounts for the sum of emissions from the three ~~four~~ divested fossil-fueled plants, the retirement of the Hunters Point Power Plant, the projected new 480 MW plant in San Francisco and the new PDEF), emissions of each criteria pollutant, except PM-10, would decrease with the inclusion of the new PDEF. PM-10 emissions ~~concentrations~~ are shown to increase in 2005 by an estimated 9 ~~20~~ tons per year regionally with the new PDEF. However, as shown in Table 4.5-26b, ~~as a percentage of BAAQMD-projected Bay Area regional emissions in 2005~~, there would be a net decrease in Bay Area power plant emissions of PM-10 and PM-10 precursors under variant 2 in 2005 compared to 1999 baseline conditions. Therefore, Bay Area power plant emissions would not contribute to the cumulative effect of increased emissions from new development in the Bay Area on regional PM-10 concentrations. ~~the change in power plant emissions of PM-10 over 1999 baseline conditions would be less than 1 percent and, therefore, would be considered a less than significant cumulative impact to regional air quality.~~

Please see response to Comment U14 for Table 4.5-26b.

September 18, 1998

VIA FEDERAL EXPRESS

Mr. Bruce Kaneshiro
Project Manager
c/o Environmental Science Associates
225 Bush Street, Suite 1700
San Francisco, California 94104

Re: Draft Environmental Impact Report Regarding Pacific Gas and Electric Company's Application for Authorization to Sell Certain Generating Plants and Related Assets (Application No. 98-01-008)

Dear Mr. Kaneshiro:

Union Oil Company of California ("Unocal"), NEC Acquisition Company ("NEC") and Thermal Power Company ("Thermal") (collectively, "U-N-T"), have reviewed the referenced Draft Environmental Impact Report ("DEIR") for Pacific Gas and Electric Company's ("PG&E's") proposed divestiture of certain generating assets pursuant to Application No. 98-01-008. This letter summarizes U-N-T's review and provides comments on the DEIR's analysis and conclusions as it pertains to the Sonoma County Geysers Power Plant Units. U-N-T's specific comments are as follows:

Alternative 3 - The Geysers Plants Are Sold To The Steam Field Operators

[Begin P1]

- The DEIR concludes that Alternative 3, the sale of the Geysers plant to the steam field operators, is an environmentally superior alternative to the proposed project. DEIR at 6-23 to 6-29. See also DEIR at 5-31, 5-35 (concluding that sustained steam production at the Geysers units would have the substantial beneficial effect of displacing the need for fossil fuels and would be a beneficial cumulative effect). U-N-T agree with this conclusion, and with the factual analysis supporting the conclusion. [End P1]

[Begin P2]

- Please explain why the noise impact would be greater under Alternative 3 than it would be under the proposed project. DEIR Table S.6, Impact 4.10-2. [End P2]

Generation Data

[Begin P3]

- According to the DEIR, Table C-1 "shows historic and available generation at the PG&E Geysers units through 1997." DEIR at C-9. U-N-T believe this statement is incorrect.

The only sources the DEIR cites for the generation numbers are PG&E's Energy Cost Adjustment Clause ("ECAC") filings. However, U-N-T cannot find any support for Table C-1's generation figures in the ECAC filings. The DEIR appears to rely on numbers in the filing that do not represent available generation under baseload conditions. For instance, it appears that Field Capacity, a defined term in the Steam Sales Agreements between U-N-T and PG&E, may have been taken to mean that the level of generation would have been available had PG&E operated the plants at maximum continuous output (at baseload). The terms of the contract specify that Field Capacity represents the peak output under a contract-specified set of plant operating constraints. This is also known as "high 5" conditions. Moreover, the decline rate shown on Table C-1 conflicts with statements in PG&E's ECAC filing. See Pacific Gas and Electric Co., Report on the Reasonableness of Operations for 1998 (January 1, 1997 to December 31, 1997), before California Public Utilities Commission in Energy Cost Adjustment Clause (San Francisco, California: Pacific Gas and Electric Co. April 1998) at 3-15. Accordingly, please clarify and provide support for the historic and available generation data reflected in the DEIR. [End P3]

[Begin P4]

- Tables C-1, S.1, S.3, 5.2, and 6-1 provide generation forecasts for the Sonoma County Geysers Power Plant Units. These generation forecasts are highly speculative, and as explained above, U-N-T believe they may be based on incorrect generation data. Accordingly, U-N-T believe the generation forecasts are incorrect. Please clarify and provide support for the generation forecasts. [End P4]

[Begin P5]

- The Geysers is a declining resource, which the DEIR ostensibly recognizes. DEIR at S-7. However, the DEIR goes on to suggest increased electrical demand will lead to increased generation from the Geysers. DEIR at 5-16, 5-19. This is inconsistent with field optimization and management techniques, and inconsistent with the historical declines in Field Capacity. This assertion may mislead prospective buyers and regulators. Please explain and provide supporting evidence for this conclusion. [End P5]

Santa Rosa Reclaimed Water Geysers Recharge Project

[Begin P6]

- According to the DEIR, "[r]egardless of who owns the plant, steam field capacity will continue to decline unless substantially more injection water becomes available." DEIR at 5-9 to 5-10. This implies that the decline in field capacity is reversible through water injection, an implication U-N-T believe is incorrect. The DEIR does not provide any support for this assertion. For instance, the Santa Rosa EIR, quoted in the DEIR, does not support the implication because that EIR predicted only a maximum potential gain of 85 MW. Further, the implication is contrary to conclusions in professional literature on water injection. Accordingly, please clarify that water injection will not reverse the decline in field capacity. [End P6]

[Begin P7]

- The DEIR states that PG&E is one of the "key players" in the Santa Rosa Wastewater Modified Geysers Recharge Project, and that "the new owners would simply assume

PG&E's role in the process." DEIR at 5-10, 5-11. These statements are inaccurate. As the DEIR indicates, the contract giving rise to the Santa Rosa Modified Geysers Recharge Project is a contract between U-N-T and the City of Santa Rosa. DEIR at 5-10. PG&E is not a party to the contract. Further, while the contract requires the supply of water for injection in U-N-T's steam fields, neither the contract nor the project includes any agreement or commitment to inject Santa Rosa water to PG&E's Sonoma plant area. In fact, PG&E has no role in the project whatsoever. Accordingly, there is no role for the new owners of PG&E's units to assume with regard to the Project.

- The DEIR states that "the current steam field operators and PG&E have entered into an agreement to inject effluent into the Geysers steam fields . . . ." DEIR at 6-24. As stated above, PG&E is not a party to the contract giving rise to the Santa Rosa Modified Geysers Recharge Project and the project includes no agreement or commitment whatsoever to inject Santa Rosa water to PG&E's Sonoma plant area. [End P7]

[Begin P8]
- According to the DEIR, as a result of the imported water supply and injection projects referenced above, "the existing units could be operated at sustained power generation rates for 20 to 30 years." DEIR at 5.11. The DEIR also states that, for units PG&E currently owns, "this would mean an assumed sustained power generation of about 700 MW for 25 years." Id. For the reasons stated above, there are no pending or proposed projects requiring reinjection in PG&E's plant area, nor is there a technical basis to conclude that such reinjection, even if it materialized, would accomplish such a level of sustained generation. Thus, U-N-T believe these statements are incorrect. Please clarify and provide support for the statements. [End P8]

Capacity Factors

[Begin P9]
- The use of the term "Capacity Factor" in Tables S.3, 5.2, 6.1 and C-1 is confusing. Specifically, according to footnote a, capacity factors are derived using a rated capacity denominator. However, the annual plant capacities that the tables list for the Geysers are derived using an estimated availability denominator. This use of different denominators within the same table is misleading. Further, it is unclear whether the term "Capacity Factors" is the same as the "Adjusted Capacity Factor" PG&E used in its filings with the California Public Utilities Commission. U-N-T believe the text and the table would be clearer if, instead of using ratios, they consistently referred to values expressed in MW or annual average power output. In the alternative, please clarify and explain the ratio's definition. [End P9]

Steam Stacking and Puff

[Begin P10]
- The DEIR's definition and characterization of "steam stacking" is inaccurate. See DEIR at S-16, 1.7, 4.5-47, 4.5-75, 6-24. In contrast to the DEIR's characterization, steam stacking is the controlled release of unabated geothermal steam at a power plant rock muffler. Steam stacking is conducted in accordance with local Air Pollution Control District regulations. [End P10]

[Begin P11]

- The DEIR's definition and characterization of "puff" is inaccurate and should be deleted. DEIR at 6-23. Puff is not related to steam stacking. Rather, puff refers to the initial increase in production from a well after it has been shut-in for a period of time. [End P11]

Natural Resources

[Begin P12]

- The DEIR states that "the steam fields in the Geysers area are being managed to prolong the steam resources to the extent possible." DEIR at 4.8-5. This is inaccurate. PG&E expressly manages its operations to maximize economic benefit to its shareholders, and has declined to make numerous investments and operating changes that would prolong resource life. For instance, it is PG&E's practice to curtail operations at the Geysers when such curtailment would result in short-term economic benefit, despite inefficient steam use and waste of a valuable natural steam resource resulting from such curtailed operations.
- The DEIR assumes that the new owners will "operate the units in a manner similar to PG&E's operation." DEIR at S-6. The DEIR also concludes that the proposed project will not promote wasteful or inefficient use of non-renewable resources because the "new owners are expected to operate the plants efficiently so that fuel is not wasted." DEIR Table S.6, Impact 4.8.2; DEIR at 4.8.4. As explained above, PG&E's operation promotes wasteful and inefficient use of fuel. Accordingly, if the new owner operates the power plants in a manner similar to PG&E's operations, the project will promote wasteful and inefficient use of a valuable natural resource. [End P12]

Steam Sales Agreement

[Begin P13]

- The DEIR assumes that, "[i]f a third-party entity with no ownership interest in the underlying steam field purchases the Geysers units, it is reasonably foreseeable that such new owner would pay a steam price similar to that paid by PG&E under its contracts with the steam field owners." DEIR at S-6. This is misleading. While the steam sales agreements between PG&E and each of Unocal, NEC and Thermal are long term legal obligations which will bind the permitted successors and assigns of the parties, the agreements contain certain provisions that are not customary, and were heavily negotiated to address certain rate recovery issues faced by PG&E. Such provisions will no longer make sense once the generating assets are transferred to a new, unregulated owner for whom rate recovery issues are irrelevant. Therefore, certain aspects of the agreements may need to be modified to accommodate a new owner. [End P13]

Cooling Tower Drift

[Begin P14]

- The DEIR discusses fallout type particulate ("FTP") issues. However, the DEIR does not discuss the impacts of cooling tower drift at the Sonoma County Geysers. U-N-T's understanding is that cooling tower drift is an ongoing problem at the Sonoma County Geysers, and has been extensively studied by PG&E. The DEIR should address the impacts of cooling tower drift inside and outside of the power plant yard. [End P14]

Other Miscellaneous Comments

[Begin P15]

- Global Change: "Condensate" should be referred to as "steam condensate." [End P15]

[Begin P16]

- Page S-21: The spacing and font used at Table S.6, Impact 4.6-4 should be conformed with the rest of the table. [End P16]

[Begin P17]

- Page 2-28: GEO should be GEP. [End P17]

[Begin P18]

- Page 2-28: U-N-T understand that SMUD's interest in the unit(s) has been acquired. Accordingly, SMUD should be replaced with the name of the entity that acquired SMUD's interest. [End P18]

[Begin P19]

- Page 2-28: U-N-T understand that Santa Fe Geothermal, Inc.'s interest in the unit(s) has been acquired. Accordingly, Santa Fe Geothermal Inc. should be replaced with the name of the entity that acquired Santa Fe Geothermal, Inc.'s interest. [End P19]

[Begin P20]

- Page 2-35: U-N-T is unfamiliar with the term "Geysers Geothermal Area." U-N-T believe the DEIR drafters may have meant to reference the Geysers Known Geothermal Resource Area ("KGRA"). [End P20]

[Begin P21]

- Page 2-35: Please confirm whether Big Sulphur Creek or Big Sulfur Creek is the correct spelling for the creek referenced. [End P21]

[Begin P22]

- Page 2-36: The last sentence of the third full paragraph should be revised as follows: add "a conceptual diagram of" before "the circulation." [End P22]

[Begin P23]

- Page 2-36: The last sentence at the bottom of the page should be revised as follows: strike "spent" and replace with "geothermal." [End P23]

[Begin P24]

- Page 2-38: The first full sentence of the first paragraph should be revised as follows: strike "evaluated as a viable" and replace with "used as a." [End P24]

[Begin P25]

- Page 2-38: The first sentence of the first full paragraph should be revised as follows: strike "purified" and "pressurized"; add "to power plants" after "insulated pipes." [End P25]

[Begin P26]

- Page 2-39: The first sentence of the first paragraph should be revised as follows: strike "is believed to"; add "s" to "increase"; strike "to"; add "s" to "increase." [End P26]

[Begin P27]

- Page 2-39: The second sentence of the first paragraph should be revised as follows: strike "Currently" and replace with "Consistent with practices during the past several years"; add "currently" before "returned." [End P27]

[Begin P28]

- Page 2-39: The third sentence of the first paragraph should be revised as follows: strike "it is expected that." [End P28]

[Begin P29]

- Page 2-39: The first sentence of the second paragraph should be revised as follows: strike "agencies" and replace with "steamfield operators." [End P29]

[Begin P30]

- Page 2-42: The first sentence at the top of the page should be revised as follows: add "Lake County" before "area." [End P30]

[Begin P31]

- Page 4.1-1: The first sentence of the fourth paragraph should be revised as follows: strike "geysers" and replace with "thermal features." [End P31]

[Begin P32]

- Page 4.1-15: The second sentence of the fourth paragraph should be revised as follows: strike "ten" and replace with "thirty." [End P32]

[Begin P33]

- Page 4.3-4: The second sentence of the second paragraph should be revised as follows: strike "steam generating conditions" and replace with "production intervals." [End P33]

[Begin P34]

- Page 4.3-12: Please clarify the second paragraph. U-N-T do not understand the paragraph's characterization of the relationship between steam generation, water supply and injection, steam reservoir pressure, and plant operation. For instance, as opposed to shutting down at some minimum threshold, a well will typically be shut-in if operating conditions of the plant cause pipeline pressure to rise above the producing pressure of the well. Further, the second sentence suggests that water only flows back to the area when wells are shut down, which is inaccurate since production tends to increase water flow into the area. Also, the last sentence of the paragraph suggests that the plants could operate continuously at full capacity but for the lack of sufficient water supply. Again, this is a misleading portrayal of the relationship between water supply and plant operation. [End P34]

[Begin P35]

- Page 4.4-10: Please consider adding Cobb Creek, Anderson Creek, and other creeks listed on page 4.4-6 to the list of prominent perennial creeks located in the vicinity of the Geysers plant. [End P35]

[Begin P36]
- Page 4.4-11, Table 4.4-2: Please note that Units 7-10, 12, 13, 16, and 20 are also close to streams. [End P36]

[Begin P37]
- Page 4.4-13: The Class V Underground Injection Control Program ("UIC Program") is a permit by rule program. Therefore, no "permits" are issued under the UIC Program. The program is implemented by DOGGR, with oversight review be North Coast Regional Water Quality Control Board. [End P37]

[Begin P38]
- Page 4.5-47: The last sentence of the first full paragraph should be revised as follows: add "controlled" after "unscheduled." [End P38]

[Begin P39]
- Page 4.5-47: The third sentence of the second full paragraph should be revised as follows: strike "relieving" and replace with "reducing." [End P39]

[Begin P40]
- Page 4.5-49: Please explain why hydrogen sulfide ("H_2S") is not included on Tables 4.5-21 and 4.5-22. Please also explain whether these tables assume all total suspended particles ("TSPs") are particles with an equivalent diameter of 10 microns or smaller ("PM-10"). [End P40]

[Begin P41]
- Page 4.9-13: The second sentence of the second paragraph should be revised as followed: add "abatement of" before "hydrogen sulfide." [End P41]

[Begin P42]
- Page 4.9-19: Please explain why sodium vanadate and hydrogen were not listed and discussed as hazardous materials representative of those found at power plants to be divested. [End P42]

[Begin P43]
- Page 4.9-22: The fifth sentence of the first paragraph should be revised as follows: add "hydrogen." [End P43]

[Begin P44]
- Page 4.11-8: The first sentence of the first paragraph should be revised as follows: add "incipient" before the word "fire." [End P44]

[Begin P45]
- Page 4.11-12: The second sentence of the fourth paragraph should be revised as follows: strike "which restricts" and replace with "and restricted." [End P45]

[Begin P46]
- Page 4.11-16: Please confirm whether the amount the Geysers Power Plant generates per year in property taxes to Lake County is $920,000 million or $920,000. [End P46]

[Begin P47]
- Page 4.14-5: The first sentence of the second paragraph should be revised as follows: strike "about 1971" and replace with "1960." [End P47]

[Begin P48]
- Page 5.8: The last bullet point should be revised as follows: strike "and existing" and replace with "an existing." [End P48]

[Begin P49]
- Page 5-23: U-N-T's understanding is that the Basin 2000 Project and the 70-acre parcel are Lake County projects. Please explain why these Lake County Projects require Sonoma County Community Development Commission review. [End P49]

[Begin P50]
- Page 5-27: The second sentence of the second paragraph should be revised as follows: strike "Condensation" and replace with "Condensate." [End P50]

[Begin P51]
- Page 5-32: The second sentence of the fourth paragraph has two periods. [End P51]

[Begin P52]
- Page 6-11: Please confirm whether PG&E is currently monitoring seismic activity associated with the Geysers' operation. [End P52]

[Begin P53]
- Page 6-23: The DEIR refers to NEC as a "Japanese turbine producer." This is inaccurate. NEC is a geothermal steam-production company. [End P53]

[Begin P54]
- Page 6-24: The last sentence of the first full paragraph should be revised as follows: strike "6 million" and replace with "8 million"; add "from Lake County" after "field." [End P54]

[Begin P55]
- Page 6-26: According to the DEIR, potential accidental discharges of contaminants to streams is a hazard for the life of the operation of the steam fields and the power plant, and "[r]unning the units at higher levels would increase the risk of an upset condition." Please explain why running the units at a higher level would increase the risk of an upset condition. [End P55]

[Begin P56]
- Page C-7: The sixth sentence of the first paragraph should be revised as follows: strike "200" and replace with "130." [End P56]

[Begin P57]
- Page C-7: The eighth sentence of the first paragraph should be revised as follows: strike "pump" and replace with "pipe." [End P57]

[Begin P58]
- Page C-7: The second sentence of the fourth paragraph should be revised as follows: strike "pressure" and replace with "production." [End P58]

[Begin P59]
- Page C-8: The fourth bullet point should be revised as follows: strike "capture" and replace with "collect"; strike "pump (inject)" and replace with "direct." [End P59]

[Begin P60]
- Page C-9: The first sentence at the top of the page should be revised as follows: strike "injections" and replace with "injection." [End P60]

[Begin P61]
- Page C-9: Please explain the statement that "changes in operations by PG&E and NCPA . . . have affected . . . the actual geology of the KGRA." [End P61]

[Begin P62]
- Page C-21: The fourth sentence of the fifth paragraph should be revised as follows: strike ", refining and retailing." [End P62]

[Begin P63]
- Page C-33, Footnote 63: In addition to the practical matters listed in footnote 63, please also note that the Steam Sales Agreement only allows for a sale of steam to a third party after a succession of tests and declarations by each party. [End P63]

[Begin P64]
- Page C-33, Footnote 65: U-N-T understand that PG&E has shut down five Geysers plants, including Unit 15. [End P64]

Again, U-N-T appreciate the opportunity to comment on the DEIR. Please contact me at (619) 236-1234 if you have any questions or require any additional information.

Sincerely,

Lisa P. Gomez
of LATHAM & WATKINS
Attorneys for Union Oil Company of California, NEC Acquisition Company, and Thermal Power Company

cc: Joel H. Mack, Esq.
Loretta Mabinton, Esq.
Joseph E. Ronan, Esq.

P. U-N-T (UNOCAL/NEC/THERMAL) (as Represented by Latham & Watkins, Attorneys at Law)

P1 Comment noted.

P2 Please see response to Comment N11.

P3 As detailed in the response to Comment N5, the steam field operators refused to provide data on steam field capacity; therefore, the interpretation of available generation and capacity is based on PG&E's representations to the CPUC and the ISO in relevant filings. The decline rate computation shown at page 3-15 in PG&E's "Report on Reasonableness of Operations" provides no context for the calculations, including whether the "high 5" conditions noted by the commenter were a factor in such calculations. The computation appears to be based on actual generation after economic curtailment rather than available generation, which is the relevant measure used in the Attachment C forecast.

P4 Please see response to Comment N5 and N6.

P5 Please see response to Comment N9.

P6 The DEIR analysis assumes that the wastewater injection projects will only slow the rate of decline of the Geysers steam fields, and will not reverse that decline. For clarification, the last sentence of Page 5-9 of the DEIR is revised as follows:

> Regardless of who owns the plants, the rate of decline of Geysers steamfield capacity ~~will continue to~~ can only be slowed if ~~unless~~ substantially more injection water becomes available.

P7 Please see response to Comments L45 and N3.

P8 Please see response to Comment N4.

P9 Please see response to Comment N6. The term "adjusted capacity factor" as used by PG&E in its filings to the CPUC is understood to be identical to the way "capacity factor" is employed in this EIR.

P10 Please see response to Comment N10.

P11 Please see response to Comment N10.

P12 The statement on page 4.8-5 of the DEIR that the Geysers steam fields "are being managed to prolong the steam resources to the extent possible" was related more to the efforts to extend the life of the fields using wastewater injection, rather than a judgment of day-to-day management practices concerning resource use decisions. Please see response to Comment N12 for further discussion on "wasteful or inefficient use of non-renewable resources."

P13 While a new owner may attempt to and succeed in negotiating new provisions in its contracts with the steam field operators, there is no way of predicting what types of contractual revisions might be made in the future. For purposes of the analysis presented in the DEIR, it is reasonable to assume that a new owner would pay comparable steam prices to those currently being paid by PG&E.

P14 Please see response to Comment N14.

P15 Please see response to Comment N16.

P16 Comment noted.

P17 Please see response to Comment N20.

P18 Comment noted.

P19 Comment noted.

P20 Please see response to Comment N23.

P21 Please see response to Comment N23.

P22 Please see response to Comment N24.

P23 Page 2-36, last sentence at the bottom of the page is hereby amended to read:

> Other sources of recharge include (1) ~~spent~~ geothermal steam condensate…

P24 Please see response to Comment N26.

P25 Please see response to Comment N27.

P26 Please see response to Comment N29.

P27 Please see response to Comment N28.

P28 Please see response to Comment N30.

P29 Please see response to Comment N31.

P30 Please see response to Comment N32.

P31 Please see response to Comment H24.

P32 Please see response to Comment N35.

P33 Please see response to Comment N36.

P34 Please see response to Comment N37.

P35 Please see response to Comment N38.

P36 Please see response to Comment N39.

P37 Please see response to Comment N40.

P38 Please see response to Comment N10.

P39 Please see response to Comment N42.

P40 Please see responses to Comments N43 and N44.

P41 Page 4.9-13, the second sentence of the first full paragraph, is hereby amended to read:

> Elemental sulfur (a nonhazardous waste) also is produced from <u>abatement of</u> hydrogen sulfide in the geothermal steam.

P42 Please see response to Comment N47.

P43 Please see response to Comment N48.

P44 Please see response to Comment N49.

P45 Please see response to Comment N50.

P46 Please see response to Comment N51.

P47 Please see response to Comment N53.

P48 Please see response to Comment N54.

P49 Please see response to Comment N55.

P50 Please see response to Comment N56.

P51 Please see response to Comment N57.

P52 Please see response to Comment N58.

P53 Please see response to Comment N8.

P54 Page 6-24 of the DEIR (last sentence of the first full paragraph) is hereby revised as follows:

> Currently, some ~~6~~ 8 million gpd are being piped up to the field from Lake County and injected in the Southeast Geysers.

In addition, the first paragraph, seventh sentence, on page 2-39 of the DEIR is amended to read:

> …able to deliver up to 8 ~~6~~ million gallons per day of effluent…

P55 Please see response to Comment N60.

P56 Please see response to Comment N61.

P57 Please see response to Comment N61.

P58 Please see response to Comment N62.

P59 Please see response to Comment N63.

P60 Please see response to Comment N64.

P61 Please see response to Comment N65.

P62 Please see response to Comment N66.

P63 Please see response to Comment N67.

P64 Please see response to Comment N68.

September 18, 1998

Mr. Bruce Kaneshiro
Project Manager
c/o Environmental Science Associates
225 Bush Street, Suite 1700
San Francisco, CA 94104

FRIENDS OF COBB MOUNTAIN COMMENTS ON THE GEYSERS PORTION OF THE DRAFT ENVIRONMENTAL IMPACT REPORT RELATING TO PACIFIC GAS AND ELECTRIC COMPANY'S APPLICATION FOR AUTHORIZATION TO SELL CERTAIN GENERATING PLANTS AND RELATED ASSETS, APPLICATION NO. 98-01-008

[Begin Q1]
First of all, we believe that it was a mistake to fold the analytical treatment of The Geysers plants into one document with PGandE's fossil-fueled plants. The Lake County Board of Supervisors, the Lake County Air Quality Management District and Friends of Cobb Mountain all requested a separate document. The differences between The Geysers plants and the others, and the issues appertaining to them, are considerable, and as a consequence of the combination, several important issues have been lost and receive no treatment at all.
[End Q1]

[Begin Q2]
A number of these issues are discussed in the comments which have been submitted to you by the Lake County Air Quality Management District. There is no point in our outlining these issues here, but in representation of the occasionally impacted residential public in the Cobb and Anderson Spring areas we request that they be given full treatment in the Final EIR.
[End Q2]

[Begin Q3]
Another important cluster of issues surrounds aging of The Geysers power plants, the declining pressures in the steam field, and the inevitable and consequent progressive need for plant closures and abandonment. These are issues which you may deem to be beyond the scope of the EIR as they are matters that PGandE would have to deal with if the plants were not to be sold, but we believe that they are highly relevant to the consideration of a change of ownership because of consequences of which both the prospective buyers and the public should be informed through objective outside analysis. The impacts will be real, and they will be significant environmentally, economically and socially. For the protection of the public and of the environment, the Final EIR should provide guidelines and stipulations for their mitigation by prospective buyers.
[End Q3]

[Begin Q4]
The level of seismic activity presently induced by commercial operations in The Geysers field may increase substantially with the implementation of the now approved City of Santa Rosa Geysers waste water injection plan. This also you have apparently considered to be outside the scope of the EIR because the plan will go forward whether there is a new operator or whether PGandE retains ownership. Here again a proposed new ownership would be moving into a new and largely unknown situation with potentially significant consequences. Again, we believe that guidelines and stipulations for mitigation are called for for the protection of the public by the agency which is in fact the Public Utilities Commission.
[End Q4]

[Begin Q5]
An ambiguity of silence runs through the DEIR with regard to the possible eventuality of PGandE selling its Geysers facilities to several parties if a single buyer is not available. We raised this issue at the recent informational meeting regarding the DEIR at Cobb on September 2nd, and were assured that a new DEIR or an addendum to the present one would be prepared in order to address the numerous additional issues that would arise if multiple ownerships should be proposed. We ask that this be clearly stated in the Final EIR.
[End Q5]

Friends of Cobb Mountain appreciate the opportunity to participate in these proceedings and we ask that we be retained throughout as a party of interest.

Submitted by

/s/

Hamilton Hess
Vice Chairman

COMMUNITY AND ENVIRONMENTAL ORGANIZATIONS

Q. FRIENDS OF COBB MOUNTAIN

Q1 Please see response to Comment I1.

Q2 Comment noted. Please see responses to Comments H1 through H71.

Q3 While the age of the Geysers units and declining pressure in the steam fields potentially leading to unit closures are legitimate areas of concern, they are beyond the scope of the EIR since these events will happen regardless of the ownership of the plants and will not be affected by the proposed divestiture. Therefore, the EIR does not include guidelines or criteria for mitigation of such occurrences by potential buyers. Note that the importation of additional wastewater for injection may reduce the rate of decline in steam pressure and delay the subsequent closure of some units. Please see the response to Comment B5 for more information on decommissioning requirements.

Q4 The Santa Rosa Wastewater Modified Geysers Recharge Project is discussed in the DEIR in the Cumulative Impacts chapter, page 5-10, and its impacts in conjunction with divestiture are analyzed in the DEIR. Please note that while the City of Santa Rosa has certified the EIR for the project and has initiated design, the federal lead agency, the U.S. Army Corps of Engineers, has not approved the Record of Decision of the EIS. The impact of this additional water source would equally affect both the new owners, if the units are sold, and PG&E if the units are not sold, so it is not an effect of the divestiture project covered in this EIR. Therefore, the EIR does not include guidelines or criteria for use of this water. The environmental effects of the use of the water are assessed in the Santa Rosa environmental document.

Q5 The DEIR clearly states in the Executive Summary (page S-5, second paragraph) and the Project Description (page 2-2, first full paragraph and bulleted items) that the proposed project entails the sale of power plants by PG&E in four packages: the Pittsburg and Contra Costa plants together (the Delta plants), the Potrero Power Plant, the Geysers units in Sonoma County, and the Geysers units in Lake County. This means that two buyers may be involved in the transfer of the Geysers Power Plant, and the DEIR addresses the potential impacts associated with two separate entities operating the power plants located in the Geysers geothermal field. The commenter is correct that, were the Geysers units to be sold to three or more operators, additional environmental effects could result. Under CEQA, if PG&E decided prior to project implementation to sell the Geysers units to three or more buyers, this EIR would have to be revisited. The CPUC would need to decide whether this EIR were sufficient for its purposes, or whether to prepare a Supplement to the EIR, an Addendum to the EIR, or a new EIR altogether. There is presently no indication that the project as defined in the DEIR has changed, or is reasonably likely to change.

Date: September 21, 1998

From: New York Landing Homeowners Association (NYLHOA)

To: Bruce Kaneshiro, Project Manager
c/o Environmental Science Associates
225 Bush St., Suite 1700
San Francisco, CA 94104

Subj: PG & E Application for Divestiture

Ref: (a) PG&E Public Meeting at PYC on 08/25/98 at 1900;
(b) PG&E "Executive Summary" for Application No. 98-01-008
(c) Application for Certification of PDEF submitted by Pittsburg District Energy Facility, L.L.C. CEC in June of 1998

Encl: (1) Copy of Ref. (c)

Reference (a) was held in accordance with applicable law and provided an oral reiteration of information contained in reference (b) with some additional commentary provided by facilitators and attendees. Reference (c) sets forth data on the PDEF power plant to be constructed by ENRON Capital & Trade Resources Corporation.

PG&E Power Plants located in Contra Costa, Pittsburg and Potrero do not exist in isolation from each other in terms of their cumulative effect relevant to current and future particulate emissions and other toxic hazardous substances. The number of existing refineries, chemical plants, other power plants and heavy industry already in place mandate that careful attention be given to the particulate matter burden already being experienced by the citizens of Pittsburg and Antioch.

Moreover, the thermal and biological effects that both the Pittsburg and Contra Costa PG&E power plants have is a significant impact now and will have in the future on all <u>living beings</u>; this fact cannot be overemphasized!

Specific comments made by your team and the public with regard to the information provided during reference (a) along with relevant questions that have been raised by myself and others are listed below:

[Begin R1]
Comment: (1) The proposed PDEF facility will have a generating capacity of 450 megawatts as shown on an overhead. [End R1]

[Begin R2]
Comment: (2) Additional power generating facilities were not included in APP.No.98-01-008 to the CPUC because they would not become operational before calendar year 2005 or they would be offset by reduced PG&E power generation. [End R2]

[Begin R3]
Comment: (3) Pittsburg and Contra Costa PG&E power plants would ideally be owned and operated by the same company due to the need for coordinated power production; but this requirement will not be a conditions of their sale. [End R3]

[Begin R4]
Comment: (4) The Pittsburg and Contra Costa PG&E power plants will still be operated by PG&E for two years after the date of sale to new owners. [End R4]

[Begin R5]
Comment: (5) The backup fuel for both Pittsburg and Contra Costa PG&E power plants will be residual oil while the PG&E Potrero power plant will use residual oil and distillate fuel oil for backup fuel. [End R5]

[Begin R6]
Comment: (6) The cumulative effect of stack emission plumes and their distribution patterns for power plants located within a fixed radius of the PG&E Pittsburg/Contra Costa power plants were not calculated and were also determined to be <u>not significant</u>. [End R6]

[Begin R7]
Comment: (7) The increase in noise level relevant to increased power generation will not be significant. [End R7]

[Begin R8]
Comment: (8) The alternative of "no project" was not considered nor was demolition of the PG&E Pittsburg power plant. [End R8]

[Begin R9]
Comment: (9) CALPINE is preparing to submit its application to the CEC for its 500 – 800 megawatt "Delta Energy Center" Power Plant located in Pittsburg. This facility will go on-line in the year 2002! [End R9]

[Begin R10]
Question (1) Why doesn't PG&E and/or ESA know that the proposed PDEF will produce 500 megawatts of power as stipulated in their application to the CEC?
[End R10]

[Begin R11]
Question (2) If the PDEF has submitted its application to the CEC for its 500 megawatt power plant and CALPINE has recently purchased the existing Dow Chemical 70 megawatt power plant for their current operations and will submit its application to the CEC within three months for its "new" 500 – 800 megawatt Delta Energy Center, then why weren't these facilities included in the "Impact Study" for the PG&E Pittsburg, Contra Costa and/or Protrero power plants application to the CPUC? [End R11]

[Begin R12]
Question (3) Given the fact that there are <u>five</u> GWF power plants and one mobile power plant in operation between the PG&E power plants mentioned in question (2) above plus PDEF and CALPINE plants, why wasn't a current baseline study for particulate matter emissions done in the area surrounding the PG&E

Pittsburg/ Contra Costa power for existing and proposed power plants? [End R12]

[Begin R13]
Question (4) Why hasn't PG&E stipulated in its application to the CPUC that it will make the purchase of offset credits by the "new" owners a condition of sale for the three PG&E power plants that it is seeking to divest in Contra Costa County? Said Offsets would be purchased from within Contra Costa County as their first priority. [End R13]

[Begin R14]
Question (5) How does the continuance of PG&E management over the new owners of the plant effect its operational profile and/or the business plan prepared by the new owners? [End R14]

[Begin R15]
Question (6) If the interruption of the natural gas supply has a low probability of occurrence, then why does the PG&E Pittsburg power plant fuel farm continue to maintain their tanks at full capacity when they are now using natural gas to fire their boilers? [End R15]

[Begin R16]
Question (7) If PG&E using the Pittsburg PG&E plant fuel farm for TOSCO refinery production storage, delivered by pipeline, and then loading tankers at their fuel pier for shipment to other locations?

Question (8) If they are using the Pittsburg PG&E fuel form for the purposes stated above, do they now have an amended USE PERMIT that allows this process to continue? [End R16]

[Begin R17
Question (9) Since Application No. 98-01-008 submitted to the CPUC by PG&E is based upon natural gas fuel statistics, what is the cumulative effect of particulate emissions for a five day period of operation for the three PG&E plants using residual oil and/or distillate fuel? [End R17

[Begin R18
Question (10) Is the Pittsburg PG&E Plant going to be designated as a "must run" facility by the PUC? [End R18]

[Begin R19]
Question (11) Is the Contra Costa PG&E Plant going to be designated as a "must run" facility by the PUC? [End R19]

[Begin R20]
Question (12) Is the PG&E Plant at Potrero going to be designated as a "must run" facility by the PUC? [End R20]

[Begin R21]
Question (13) Is the PUC aware of the fact that CALPINE is in the final stages of submitting its application to the CEC for its 500 – 700 megawatt power plant in Pittsburg? [End R21

Thank you for your consideration of these comments and questions.

Respectfully,

/s/

William G. Glynn
President, NYLHOA

R. NEW YORK LANDING HOMEOWNERS ASSOCIATION

R1 Comment noted. Please also see response to Comment B17.

R2 It is assumed that the commenter is referring to the cumulative analysis contained in the DEIR, and not to PG&E's pending application to sell power plants. The cumulative analysis is contained in Chapter 5 of the DEIR. Every effort was made to include all known (at the time of the preparation of the DEIR) proposed power projects having the potential to result in cumulative impacts with the project. Cumulative impacts were analyzed for the year 2005, so only proposed projects expected to be implemented by 2005 were included (with the exception of cumulative air quality analysis conducted for 2015). The commenter is correct that, for the most part, proposed new power plants were not assumed in conjunction with the sale of PG&E's existing plants. The reason for this is that power plant environmental impacts are primarily localized (e.g., air emissions and noise) and, if additional new plants throughout the state were assumed, the analytical maximum capacity factors of the plants proposed for sale would decline due to finite demand for electricity. Thus, in order to conservatively portray cumulative impacts in the context of this divestiture project, assumptions were selected so as to maximize, rather than minimize, generation at the plants for sale. Please see page 5-7 of the DEIR (first paragraph) for an explanation of how proposed new power plants were treated in the cumulative analysis.

R3 The DEIR states in numerous locations that the proposed divestiture includes the sale of the Pittsburg and Contra Costa plants (the Delta plants) together as a single package. The DEIR addresses the potential impacts associated with operation of these two plants by a single owner. The DEIR also analyzes as Alternative 2B the sale of the Pittsburg and Contra Costa plants to separate owners (see DEIR pages 6-16 through 6-23).

R4 The commenter is correct. This is a requirement of AB 1890.

R5 The commenter is correct. The backup fuel for both Pittsburg and Contra Costa plants is residual oil. At the Potrero plant, residual oil is the backup fuel for Unit 3, while the three Potrero combustion turbine units (4, 5, & 6) can only use distillate as fuel, i.e., there is no backup fuel for these three units. As is noted repeatedly in the DEIR, any use of residual oil at any of these plants is governed by BAAQMD rules and regulations and is only permissible in specific, limited circumstances.

R6 The air quality analysis conducted for the DEIR did account for the proposed cumulative projects (those listed starting on page 5-5 of the DEIR). Please see the response to Comments B6 and B15 for a full discussion of this issue.

R7 The commenter is correct. As stated in Impact 4.10-2 of the DEIR, potential increases in ambient noise associated with project-related operational changes at the divested power plants would not be significant.

R8 The No Project Alternative (PG&E retaining ownership of the plants) is evaluated as Alternative 1 in Chapter 6, Alternatives Analysis, of the DEIR. The commenter is correct that demolition of the Pittsburg Power Plant was not included in the alternatives examined in the DEIR. That plant, which continues to be a viable power plant, is designated by the ISO as “Reliability Must Run” and, in particular, is needed during summer months to support the local 115 kV distribution system. There was therefore no reason to examine demolition of the plant as one of the project alternatives since it is neither a reasonably foreseeable occurrence nor a feasible alternative to the sale of the plant.

R9 The commenter is making a point that the Calpine Delta Energy Center will go on-line in the year 2002. The commenter is referred to responses to Comments B6 and B15, which address this proposed power plant project.

R10 Please see response to Comment B17.

R11 The Pittsburg District Energy Facility (PDEF) is included in the DEIR as part of the cumulative analysis (Section 5.3.4, commencing on page 5-39). The DEIR studies the impacts of the sale of the three PG&E fossil-fueled power plants, as well as the Geysers geothermal units. The DEIR is not an analysis of the construction of Calpine’s proposed Delta Energy Center Project (DECP) facility as that facility will undergo its own environmental review by the CEC. The DECP was not included in the DEIR because the potential for the DECP actually being constructed was unknown until a few days prior to publication of the DEIR. The cumulative effects with the proposed DECP are analyzed in the response to Comment B15. As this FEIR goes to press, Calpine has still not filed an Application for Certification with the CEC for the DECP; it is expected to do so by the end of 1998.

According to Calpine, generation from the existing 70 MW facility on the Dow Chemical site in Pittsburg will decrease substantially once the DECP facility is on-line because Calpine intends to convert the existing facility into a peaking plant. Conversion to a peaking facility would result in significantly reduced generation at the existing 70 MW facility, and Calpine intends to apply to the Bay Area Air Quality Management District for emissions credits earned from the reduced generation at the existing facility and apply those credits to the new facility (Brian Bertacchi, Calpine DECP Plant Manager, November 1998). Thus, studying the future cumulative effects of generation from both the existing 70 MW facility and the proposed DECP is essentially equivalent to studying the proposed DECP alone because emissions credits earned from reducing generation at the former will be applied to the latter. In other words, Calpine intends to mitigate the air quality impacts of the new facility by reducing the air quality impacts at the existing facility. This should result in a net positive benefit because air emissions credits earned are a factor of at least 1.15 higher than air emissions credits applied, i.e., for every ton of emissions from the new facility, Calpine must reduce emissions from the old facility by at least 1.15 tons (BAAQMD Regulation 2, Rule 2, Section 2-2-302).

R12 Table 4.5-31 on page 4.5-67 and Table 4.5-32 on page 4.5-69 of the DEIR present particulate matter background concentrations at the Bethel Island air quality monitoring station that are used for the analysis in the DEIR. The PM-10 background values (except the annual averages) represent the average of the 2nd highest values recorded each year from 1994 to 1996. Using long-term data from the BAAQMD monitoring stations to determine conservative future background concentration levels is standard practice for determining future forecasted background levels. Using District data assures that the data is as accurate as can be measured because it goes through strict quality control steps developed by the BAAQMD and the California Air Resources Board. Because PM-10 is considered to be a regional pollutant, the data from the Bethel Island station is considered to be a good indication of PM-10 concentrations in the area of all the Delta power plants. Short-term site-specific measurements would not be expected to have the data integrity of BAAQMD monitoring stations, and would be unlikely to suggest that a higher background concentration would be more appropriate than the 2nd highest value recorded over a three year period at a BAAQMD monitoring station.

R13 It should be noted that PG&E has proposed to sell two power plants in Contra Costa County (not three). Also, from a regulatory standpoint, no offsets are required for the emissions increases identified in the DEIR since such increases would be allowed under existing air permits. Offsets are generally required only in connection with new stationary sources or major modifications to existing stationary sources.

R14 There will not be any PG&E management over the new owners. As mentioned on page 2-6 of the DEIR, PG&E personnel will operate the plants at the direction of the new owners pursuant to the Operation and Maintenance Agreement (O&M Agreement) that will have a term of two years after the sale closes. California Public Utilities Code Section 363 requires PG&E (or an affiliate) to operate and maintain the plants for at least two years to "ensure the continued safe and reliable operation" of the plants. Under the Agreement for each plant, PG&E will serve as an independent contractor of the new plant owner, and will provide all operation and maintenance services as directed by the new plant owner, consistent with the terms of the O&M Agreement. Specifically, PG&E will provide a safety supervisor, first line supervisors, operators, maintenance personnel, and other bargaining unit employees. The new owner will provide all other personnel at the plant, including all other management personnel. The form of the O&M Agreement has been reviewed and approved by the CPUC.

R15 None of the fuel tanks at the Pittsburg plant are full. Several tanks do contain fuel oil. Per an agreement with the CPUC, PG&E maintains an oil inventory sufficient to provide about three weeks of operating capability for the plant in the event of a natural gas curtailment (CPUC Interim Decision, Application 96-04-001, 12/20/96).

R16 PG&E is not currently storing or shipping product from the TOSCO refinery. The Pittsburg Power Plant and the TOSCO refinery are not connected by pipeline.

R17 As stated in the DEIR, BAAQMD Regulation 9, Rule 11, which was adopted in 1995, prohibits the PG&E plants from using fuel oil in the steam boilers except for a *force majeure*. (*Force majeure* natural gas curtailment refers to an interruption in natural gas service due to an unforeseen failure or malfunction, an unexpected and uncontrollable event such as a natural disaster, or a curtailment pursuant to CPUC rules or orders.) A detailed discussion on emergency conditions under *force majeure* is given in footnote #6 on page 4.5-17 of the DEIR. Since 1994, the PG&E plants have not used residual fuel oil in the boilers. If in the future there is an emergency condition that may require the use of fuel oil for a short time, the impacts would be similar to those analyzed in the Health Risk Assessments (HRAs) that were carried out for the plants in 1992/93 to comply with the Air Toxics "Hot Spots" rule (AB2588). During this time period, fuel oil was occasionally used at the plants. The health risks from fuel oil usage were shown to be well below the cancer risk significance threshold of 10 in a million and were below the hazard index significance criterion of 1.0 for acute and chronic exposure to non-carcinogens.

With respect to distillate fuel, the only units that are equipped to burn this fuel are the combustion turbines at the Potrero plant. The operation of these turbines is limited to 10 percent of the year (870 hours per year), usually under maximum power demand conditions. Operation of the combustion turbines was addressed in the DEIR when determining possible worst-case short-term impacts. These impacts are also less than significant.

R18 The Pittsburg plant is designated as "must run" with a Reliability Must Run Agreement (RMRA) by the ISO, as discussed at page C-11. The CPUC has no role in designating whether power plants are designated "must run."

R19 The Contra Costa plant is designated at "must run" with an RMRA by the ISO, as discussed at page C-11. The CPUC has no role in designating whether power plants are designated "must run."

R20 The Potrero plant is designated at "must run" with an RMRA by the ISO, as discussed at page C-11. The CPUC has no role in designating whether power plants are designated "must run."

R21 Please see the response to Comment B15.

CPUC PUBLIC MEETING COMMENT SHEET

Name: Michael Alexander
Address: San Francisco Beautiful
1717 Mason St.
San Francisco, CA 94133
Telephone: 415 441-6700

[Begin S1]
Comment: Our concerns are for public access, noise levels, natural and species habitat, views and aesthetic clutter. Except for The Geysers, all these plants are adjacent to San Francisco Bay, on the route of the San Francisco Bay Trail. This EIR process involving the transfer of ownership, appears not to deal substantively with our concerns, since no change in already degraded environment produces no environmental impact (according to the EIR).
[End S1]

However, post-sale changes in structures or operations may impact our areas of concern. Therefore, I ask to be kept on a notification list indefinitely, to learn of any changes in any of the site (except The Geysers), so that we may comment on their environmental impacts.

S. SAN FRANCISO BEAUTIFUL

S1 The commenter appears to recognize that it is beyond the scope of this EIR to attempt to reverse environmental degradation unrelated to the proposed project and which has accumulated after more than a century of industrial and commercial development on and around San Francisco Bay. The DEIR does acknowledge that changes related to the project may result in adverse environmental effects in some of the areas of concern to the commenter. These potential effects are addressed in detail in the appropriate sections in Chapter 4 of the DEIR.

Regarding future notification, the CPUC does not anticipate being involved in any future changes in power plant structures or operations and therefore does not maintain any notification lists related to such activity. The commenter may request to be placed on notification lists maintained by the CEC and the planning and building departments of the jurisdictions in which the San Francisco and Delta power plants are located by contacting those agencies directly.

September 11, 1998

Bruce Kaneshiro
CPUC EIR Project Manager
c/o Environmental Science Associates
225 Bush Street, Suite 1700
San Francisco, CA 94184-4207

Re: Proposed Divestiture of Electric Generation Assets by Pacific Gas and Electric Company Application No. 98-01-008

Dear Mr. Kaneshiro:

On behalf of the seven thousand Sierra Club members of the Redwood Chapter, we are commenting on the Draft Environmental Impact Report for the Divestiture of PG&E's 14 Power Plants at The Geysers.

[Begin T0]
Attached is a list of comments on deficiencies or errors in the DEIR environmental assessment. Some comments could not be addressed to specific areas in the DEIR because they were never raised. We find the DEIR is deficient and a re-issuance of the DEIR is necessary to address the issues as follows.
[End T0]

We recognize and appreciate the step taken by the CPUC of conducting an environmental review under CEQA.

Sincerely,

/s/

Krista Rector
Redwood Chapter Executive Committee

Cc: Mile Reilly, Supervisor, Sonoma County
Rue Firch, Planning Commissioner, Sonoma County
Senator Mike Thompson
Representative Virginia Strom-Martin,
Tara Mueller, Esq.
Rich Ferguson, CEERT Representative

[Begin T1]
1) The listing of the steelhead and coho salmon under the Federal Endangered Species Act is a significant change in circumstances since the project was first authorized. Therefore, the project's impacts on steelhead and coho salmon must be considered in the DEIR. (See CEQA Guidelines, 14 Cal. Code Regs. Section 15065.)
[End T1]

[Begin T2]
2) The DEIR's "environmentally baseline" against which the project's impacts must be measured is non-existent for the project. This is different from the "no project" alternative, which is continued operation of the project under its' current ownership. (14 Cal. Code Regs Section 15125, 15126(d).)
[End T2]

[Begin T3]
3) The DEIR's alternatives analysis must consider decommissioning of the project plant(s) as one of the reasonable and feasible alternatives. (Id., 15126(d).) One reason alone would be the effect of Proposition 9. According to the Analysis of the California Energy Commission's "Preliminary Analysis of the Utility Rate Reduction and Reform Act", rate levels for residential customers of PG&E would plunge 26 percent starting in January, 1999. PG&E would be impacted due to a $2.9 billion debt for the Diablo Canyon plant in addition to The Geysers plants, including debts for Units 21, 22, 23 and 24 which were never built. Another reason you give on pg 3-7 is that "PG&E would not be required to sell its plants, and it is not certain that the plants would be sold" thus leaving it open ended to financial decisions to decommission.
[End T3]

[Begin T4]
4) The DEIR must consider the full range of environmental impacts, direct and indirect, short term and long term. Year 2005 is not sufficiently long term. (14 Cal. Code Regs. Section 15126.)
[End T4]

[Begin T5A]
5) See CEQA Guidelines Appendix G for effects that are normally treated as significant. We argue that certain impacts must treated as significant and mitigation measures adopted for these impacts, see Item C – "Substantially affect a rare or endangered species of animal of plant or the habitat of the species." (14 Cal. Code Regs. Section 15000 et seq, App. G.) Since the permits for the plants were issued, the threatened listing of Russian River Central Coast ESU for steelhead (Oncorhynchus mykiss) took place on 8/11/97 and Russian River Central Coast ESU for Coho salmon (Oncorhynchus kisutch) took place on 10/31/96. (Refer to Federal Registers Vol. 63, No. 18 and Vol. 62 No. 159.) Big Sulphur Creek, a main tributary of the Russian River, drains The Geysers 85 mile watershed and is a steelhead habitat nursery.[End T5A] [Begin T5B]In addition, you state that hydrogen sulfide in Sonoma County would increase and The Geysers is probably the largest source of atmospheric sulfur in California (Suter, 1978) and sulfur dioxide has been shown to be a phytotoxicant or a poison to plants.
[End T5B]

[Begin T5C]
Please refer to the "Geysers-Calistoga KGRA Fish Populations and Element Loads" published in June, 1990 by the University of San Francisco with oversight by Steven Sharpe of the Sonoma County Department of Planning and the California Energy Commission.

This report published the results of studies on fish muscle and organ tissue showing the impacts of chemical element levels impacts from Geothermal activity. A copy of the report is available from Steve Sharpe, who is located in the LAFCO Agency in Santa Rosa or you may contact the author of this letter. Also please refer to "The Potential Impacts on Aquatic Ecosystems From the Release of Trace Elements in Geothermal Fluids" by Cushman, Heldebrand and Brocksen (Environmental Sciences Division Publication NO. 1097, October, 1997.) This addresses the bioaccumulation hazard in the Big Sulphur Creek region. Please refer to the files at the Northern California Regional Water Quality Control Board on the condensate spills to local water ways and fish kills (files: 6/85, PG&E, 20,000 gallon spill; 4/86, Unocal, 540 gallons, Big Sulphur Creek; 8/86, Unocal, 11,440 gallons, Big Sulphur Creek; 2/87, NCPA, 15,000 gallons, Big Sulphur Creek; and 4/88, PG&E, 30,700 gallons, Big Sulphur Creek as examples.)

[End T5C]

[Begin T5D]

It is particularly notable that in Table 2.3 pg 2-45 "Partial List of Federal, State, Regional And Local Permits and Requirements Applicable to PG&E's Proposed Divestiture" that you have not indicated any requirements for The Geysers from the National Marine Fisheries Service despite ESA listings and the history of spills.

[End 5D]

[Begin T5E]

On pg 4.7-33 and 34 your assessment of adequate mitigation is to have PG&E hand over materials (unidentified) and a subsequent signing of a disclosure form noting the new owner received the forms. This constitutes all action necessary to "mitigate" impacts to endangered species. If touching the Bible were equivalent to clean living then all us Bible holders would be free from all sin.

[End T5E]

[Begin T6]

6) See CEQA Guidelines Appendix G for effects that are normally treated as significant. We argue that certain impacts must be treated as significant and mitigation measures must be adopted for these impacts, see Item F. "Substantially degrade public water supply" (14 Cal. Code Regs. Section 15000 et seq, App. G.) The City of Cloverdale's historic water extraction rights, since the later 1800s, is from Pluton Creek, a tributary of Big Sulphur Creek, and from the confluence of Big Sulphur Creek with the Russian River. Today, the intake water wells are pulling from the gravels beneath the Russian River at the confluence. The City wells supply the drinking water for 6,000 people.

[End T6]

[Begin T7]

7) See CEQA Guidelines Appendix G for effects that are normally treated as significant. We argue that certain impacts must treated as significant and mitigation measures adopted for these impacts, see Item X. "Violate any ambient air quality standard, contribute substantially to an existing or projected air quality violation, or expose sensitive receptors to substantial pollutant concentrations." (14 Cal. Code Regs. Section 15000 et seq, App. G.) You have not addressed in adequate manner the impacts of radon other than a "nod" on pg 4.5-47. Even though you point out on pg E-9 the California Energy Commissions concern and requirement for a significant number of Plant Units to contact them immediately if Radon exceeds standards.

[End T7]

[Begin T8]

8) Financial impacts on the environment are significant because of the potential that bankruptcy and insufficient bonds will result in an inability to clean up the environment. If a single owner, such as a steam field leaseholder, purchases a plant, then their capital is sunk deeper into the same potentially insolvent generation unit. Please see the results of the Geo Operator Corporation bankruptcy that resulted in 24 leaking wells in 1997 in Sonoma and Mendocino Counties. Geo's bonds were inadequate and could only address one well head in Mendocino, leaving the remaining 23 wells to be repaired with County and State funds of over $2 million. The wells had to be replugged because of leaking hydrogen sulfide killing any living thing within hundreds of yards. (4/11/97 Final Report on GEO Abandonment filed with Sonoma County Planning Dept. and available in local libraries.)

A mitigation step should be included that would require a bonding requirement of the new owners to a level that would ensure that decommission and habitat restoration is done correctly and completely. This should be extended to address all directly related environmental damage. In addition, sufficient funds should be collected from plant operators to provide for inspections and monitoring by an independent party responsible to the public.

[End T8]

[Begin T9]

9) The DEIR mentions the current and future projects for LACOSAN and Santa Rosa for injection of wastewater into 14-28 injection wells to "kickstart" the production of steam. However, there is the potential that the LACOSAN project may not be successful, and that the Santa Rosa project may not take place. You neglect in pg 2-36 to mention any of the other impacts of the steam constituents beyond sulfur. What has been unaddressed in this DEIR is the increase of corrosive solutes in the geothermal steam that have produced high levels of chloride at the wellhead with observed levels greater than 100 ppm. The chloride-bearing steam is acidic and highly corrosive and, as The Geysers reservoir dries out over time, the production of higher levels will increase with resultant long-term significance. You noted on pg C-8 that "Note that a change to cycling operations increases maintenance costs, due to the higher variability of operations and/or increased corrosion in the steam wells." You will need to reassess the impacts on both financial and environmental conditions from a continued increase of corrosive acids over the long term.

Also, item 7. on pg. S-12 stating that "the two proposed waster injection projects....are being implemented and have helped to stabilize generation capacity at the Geysers plant" is highly speculative and false, since not one inch of pipe has been laid for the more massive project. It is hard to believe that a proposed project has such far-reaching capabilities as to effect production when nothing, in fact, has occurred.

[End T9]

[Begin T10]

10) On Pg. S-5 and 2-7, please elaborate on the statement that "PG&E will retain certain liabilities for existing contamination of soil and groundwater and will be responsible for conducting remediation activities of such contamination after the sales." What liabilities? What sites? What contamination? What groundwater and water hydrology courses? What mitigates the contamination? What are the standards that must be reached? On pg. 4.9-13 you note that PG&E hasn't completed a Risk assessment to determine the nature and extent of the contamination.

[End T10]

[Begin T11]
11) Pg. S-5 The statement that "The Purchase and Sale agreement for each plant requires a deed restriction that prevents the new owner from using the site for residential or other sensitive uses" should also contain the following: "deed restrictions also commits the new owner to uphold all plant EIR mitigations that stipulated a return to native habitat after the decommissioning of the plant."
[End T11]

[Begin T12]
12) On pg S-17 and 1-7 you mention that one of the areas of controversy is "the potential for the sales to increase diversions from creeks in the Geysers area" however, you never address this issue in any way in the DEIR, nor is there any attempt to show whether there is a significant impact nor an offsetting mitigation to the effect. There are almost 100 applications for increased water diversion from the Russian River and it's tributaries pending before the California Division of Water Rights. One of the two largest is an application by UNOCAL to extract additional water from the Big Sulphur Creek tributaries. Please contact the DWR for information or let the writer of the letter know that you need help and information will be supplied. What creeks are you referring to? Please note that on pg 4.4-16 you state "Changes in production at the Geysers would not be expected to affect water quality or quantity." Which is it? Affect or no affect?
[End T12]

[Begin T13]
13) On pg. 2-6 you state that the sale of the power plants is to occur under the following terms and conditions, "The Geysers Power Plant will be offered for sale through a competitive bidding process to buyers who are qualified to ensure that the plant operates when needed for system reliability, and, when no longer needed, to conduct any required decommissioning in a responsible manner." Please give specific qualifications by which actions are to be ensured. What are the specific tasks that they will conduct in order to decommission in a responsible manner?
[End T13]

[Begin T14]
14) On pg 2-38, we take exception to the statement that "geothermal steam is expanded through a steam turbine and cooled and condensed into water..." When, in fact, the condensate contains a vast number of toxic substances. These toxic substances are the reason condensate is reinjected instead of shipped out of the area. The original permit granters were afraid to ship that much waste over the Highways of California since the only site that could take something of this high of level of toxicity was Kettleman Hills in Southern California. You need to adequately address the environmental impacts from the handling of potentially increased amounts of condensate.
[End T14]

[Begin T15]
15) You outline in Table 2.2 the fact that 14 Units are using outdated technology for "scrubbing" Hydrogen Sulfide. There are a significant number of the plants that don't use Stretford systems. You are responsible to address the environmental impacts and the potential for mitigation from decommissioning plants with non-Stretford systems and addressing the uncoupling of some plants from a single sale and bid proposal.
[End T15]

[Begin T16]

16) It is noted on Pg 4.5-45 that you have included "Annual Wind Rose" patterns for air particulate impacts for all the plant sites except for The Geysers. This is notable when on pg 4.5-75 you note that hydrogen sulfide emissions will increase by 40% in the Sonoma County plants. We can only assume that you did not have them available. Please contact the Regional Air Quality Control Board or the author of this letter and air patterns will be made available to you. The fallout in The Geysers is notable and there are Deer Lung studies available. Please contact or visit the Regional Library in the town of Lakeport.

[End T16]

[Begin T17]

17) On pg 4.8-2 you make an interesting statement that the problem with The Geysers is that it is "not a 'unitary' steam field; i.e., each operator is not 'assigned' a percentage of the field to utilize. Instead, the more wells an operator builds, the more the operator is free and able to tap the resource. As a result, too many wells have been used to tap the KGRA. The steam resource is being unsustainably drawn upon, and the steam pressure from the field has been dropping for many years, currently to as low as 200 pounds per square inch (psi) from a peak of 500 psi." What you haven't addressed is what this impact has on the productivity and potential shutdown of certain plants. Nor have you addressed the issue that the root problem could exacerbate an accelerated shutdown of the resource extraction and the resultant impacts and mitigations.

[End T17]

[Begin T18]

18) On pg 4.9-20 and E-5 you list hazardous materials at the power plants as less than significant. You mention asbestos as insulation material, but you may be unaware that The Geysers contains two unique materials, serpentine or asbestos and cinnabar or mercury. There are many abandoned mines and tailing sites going back approximately 100 years. The sites should be identified and OSHA requirements should be explained to new owners, including the run off pattern into area water ways. This would be significant for Plant #14 and "has four pumps in the turbine room from constant standing water" and from the floorplan layouts of the plants showing significant number of "sump/pump", "standing water", and "drainage pipe" sites. Also worthy of note is Plant #15 which was built directly upon a mercury mine (Bedrossian, 1980). A mercury retort and mine tailings are adjacent to the Filley 1 well pad. As stated by Mark Walters in "Geochemical Aspects of the Unit 15 Steam Field", that "therefore it is no surprise that steam from the Unit 15 steam filed contains mercury and associated elements." This is one example of many found easily in literature going back to the 1960s and can be found through a simple online search at the downtown Santa Rosa library.

[End T18]

T. SIERRA CLUB REDWOOD CHAPTER

T0 Comments on specific alleged deficiencies or errors are addressed individually as they are raised in the commenter's subsequent comments. The CPUC disagrees with the commenter's assessment of the DEIR as deficient. Therefore, there is no need to re-issue the document.

T1 Potential impacts to steelhead trout and coho salmon at the Pittsburg and Contra Costa Power Plants are discussed under Impact 4.7-2, and mitigation is provided under Mitigation Measure 4.7-2. These two species are not expected to be impacted by operations at the Potrero Power Plant, where occurrences of salmonids are rare. Big Sulphur Creek in the vicinity of the Geysers is an important steelhead spawning and rearing stream. However, there is nothing inherent in the normal operating processes of the Geysers Power Plant that would constitute a "take" of a listed species, and thus the change in listing status is not relevant to the CEQA analysis. Should a "take" occur as a result of equipment failure (e.g. geothermal condensate spill) or personnel negligence, the enforcement of the provisions of the Endangered Species Act would be no different whether PG&E or another entity owned the power plant.

T2 It is not clear why the commenter believes that the environmental baseline is nonexistent. The Baseline scenario for 1999 is defined on pages 3-2 and 3-9 through 3-12 of the DEIR and is used as a basis of comparison in evaluating all environmental impacts discussed in the DEIR. As noted in the DEIR, the baseline reflects the ongoing restructuring of the electric utility industry that will continue to occur with or without implementation of the proposed project.

T3 Proposition 9 was on the ballot in California on November 3, 1998 and was defeated. Regarding decommissioning, please see the response to Comment B5.

T4 As noted in the comment, the intention of the CEQA requirement to address both short-term and long-term significant effects of the project is to ensure consideration of the full range of environmental impacts associated with the project. The year 2005 was selected for analysis of long-term effects for the following reasons: (1) the restructuring of the electric industry will be complete by then; (2) for purposes of a cumulative analysis, it is difficult to anticipate future projects beyond that date; (3) a variety of anticipated changes in the regional electricity generation and transmission system will have been implemented by 2005; and (4) beyond that date, physical and operational differences between restructuring with divestiture as currently proposed and without divestiture could be effectively eliminated. In this context, evaluating potential effects through the year 2005 does encompass the potential long-term effects of the project. Please also note that the air quality analysis also considers longer-term cumulative air quality effects in 2015, based on populations projections supplied by the Association of Bay Area Governments and extrapolations of air quality projections developed by the BAAQMD.

T5a Please see response to Comment T1.

T5b The commenter implies that hydrogen sulfide will convert to sulfur dioxide, which is a phytotoxicant to plants, and will result in ambient air levels that are great enough to damage plants. Studies indicate that the conversion of hydrogen sulfide to sulfur dioxide in the atmosphere is a slow process (Seinfeld, 1986 and Baulch, et al., 1982), with typical conversion times being over 53 hours. Within that time period, pollutant emissions from the Geysers plants would be transported many miles downwind, and concentrations of these pollutants would be extremely small because of dilution by the air. Therefore, hydrogen sulfide conversion to sulfur dioxide at these larger distances from the plants would result in levels well below those that could affect plants.

In addition to the response, the following references are hereby added to the reference list for Section 4.5, Air Quality, on page 4.5-84 of the DEIR:

Seinfeld, J.H., *Atmospheric Chemistry and Physics of Air Pollution*, John Wile & Sons, pages 164-169, 1986.

Baulch, D.L., R.A. Cox, P.J. Crutzen, R.F. Hamilton, F.A. Kerr, J. Troe, and R.P. Watson, *Evaluated Kinetic and Photochemical Data for Atmospheric Chemistry*, J. Phys. Chem. Ref. Data, Vol. 11, 1982.

T5c It cannot be assumed that the proposed divestiture of the Geysers Power Plant will result in an increase in geothermal condensate spills because it is not projected that divestiture would lead to additional accidents. Therefore, the concern, while valid, does not constitute an impact of divestiture.

T5d PG&E has not received any National Marine Fisheries Service (NMFS) requirements for the Geysers. The Secretary of Commerce, through NMFS, has not yet issued a Protective Regulations ruling for steelhead trout under Section 4(d) of the Endangered Species Act of 1973. Until such a ruling is made, NMFS is acting in the role of advisory agency rather than regulatory agency with respect to threatened steelhead.

T5e The proposed divestiture project, i.e. the transfer of ownership of PG&E's power plants, is not expected to have any impacts on special status species other than those discussed in Impacts 4.7-1 and 4.7-2. Mitigation Measure 4.7-1 addresses the need for future owners to be aware of all biological resources within the project area so as to not impact these resources through unforeseen, non-power-production activities such as equipment storage, maintenance practice changes, road access, facility repair, etc. To clarify that the materials provided by PG&E to the new owners must be readily accessible, Mitigation Measure 4.7-1 on page 4.7-34 of the DEIR is hereby amended as follows:

Mitigation Measure 4.7-1 PG&E shall provide ~~Provide~~ future plant owners with informational materials and training documents in PG&E's possession concerning jurisdictional wetlands and special status species and habitats in the vicinity of the power plants to be divested. This material shall be indexed and organized in a manner that is readily accessible to the new owners.

T6 Section 4.4.3, Significance Criteria, includes both CEQA Appendix G, Item (f): Substantially degrade water supply; and Item (g): Contaminate a water supply. As described in Impact 4.4-1, the project would have minimal, if any, effects on water quality.

T7 The measured concentrations of radon are typical of safe background levels and well below levels causing health problems. As a precaution to prevent exposure levels from exceeding health levels, the Air District requires that radon levels be monitored near the Geysers project. There are typographical errors on page 4.5-47 that lead to the wrong conclusions. Thus the text regarding radon in the third sentence of the third full paragraph on page 4.5-47 of the DEIR has been changed to read:

> The measurements ~~indicated~~ showed levels ~~of radon~~ ranging from ~~3~~ 0.3 to ~~5~~ 0.5 pico-curies per liter of air, which is below ~~above~~ typical background levels of 1 pico-curie per liter (1998, personal communication with Lake County APCD).

T8 The steam field operator referenced in the comment did go bankrupt and abandon 24 leaking wells in the Geysers Known Geothermal Resource Area in 1997. U.S. Environmental Protection Agency Superfund monies were used to cap seven of the wells, and a grant from the CEC provided the funds to cap all but one of the remaining wells. The one uncapped well is not currently considered an environmental threat. Please note that potential buyers of the project power plants will be carefully screened for financial solvency and will be subject to CPUC approval. Regarding decommissioning, please see responses to Comments B5 and K1.

T9 The increase in cycling operations discussed in Attachment C is going on currently, and has been going on since 1994. Increased cycling would not be a consequence of divestiture, although restructuring may encourage cycling by altering the economic incentives faced by any owner, whether it be PG&E or a new buyer. For this reason, analyzing the impacts of cycling is beyond the scope of this DEIR.

The Lake County effluent pipeline currently is able to deliver at least 8 million gallons per day (mgd) to the Southeast Geysers area (see the response to Comment P54). Although smaller, this is still comparable to the proposed 11 mgd capacity for the Santa Rosa pipeline. The Lake County line has been in operation less than a year, but has already increased generation capacity at the affected PG&E units by about 40 MW, which is an average of 10 MW apiece for Units 13, 16, 18 and 20, the four units affected. Also please see the response to Comment L15. It appears that, if anything, the DEIR had underestimated the potential improvements from these projects.

The comment faults information presented in the Project Description (on page 2-36 of the DEIR) for failing to address constituents of the geothermal steam. Such constituents are described elsewhere in the DEIR where relevant. For example, chemical constituents found in geothermal steam are mentioned on page 4.9-12. (Also, as noted on page 4.4-12 of the DEIR, the Geysers plant has a zero water discharge program and therefore needs no NPDES permit nor wastewater discharge requirements.)

The commenter alleges that there are "corrosive solutes in the geothermal steam that have produced high levels of chloride at the wellhead with observed levels greater than 100 ppm." The commenter goes on to claim that "the chloride-bearing steam is acidic and highly corrosive..." However, the commenter provides no basis for these assertions. In fact, steam or water having chloride concentrations of "greater than 100 ppm" would be neither "acidic" nor "highly corrosive." The chloride ion by itself is a neutral ion (a constituent of table salt) that imparts no acidic quality to steam or water, and low concentrations of 100 ppm chloride are not corrosive. Given the fact that the drinking water standard for chloride is 500 ppm, a concentration of 100 ppm of chloride would not be considered a "high level" by any authority. It follows that the claim that it could be "highly corrosive" or "acidic" appears unreasonable.

The commenter's assertion that the statement on page S-12 of the DEIR ["7. The two proposed wastewater injection projects...are being implemented..."] is "highly speculative and false" is mistaken. The DEIR text is correct as written. The DEIR is merely stating the cumulative assumptions for the year 2005, not claiming that the projects are happening now or are guaranteed to happen as the commenter seems to imply. The commenter is correct that the proposed projects may in fact not ultimately be approved or implemented, but CEQA requires that the cumulative analysis assume that proposed projects actually will occur.

T10 The comment focuses specifically on the Executive Summary of the DEIR and on Chapter 2, the Project Description. However, the concerns of the commenter regarding existing contamination and cleanup are discussed in the local setting and impact descriptions for the Geysers Power Plant in the Hazards section of the DEIR. The Hazards setting for the Geysers Power Plant begins on page 4.9-12. Impacts of remediation are discussed under Impact 4.9-1, which starts on page 4.9-14, and under Impact 4.9-2, which can be found on page 4.9-18.

The Phase II Environmental Site Assessment and the Risk Assessment have now been completed for the Geysers Power Plant. The findings and conclusions of the Phase II Environmental Site Assessment and the Risk Assessment do not modify the analysis nor conclusions of the DEIR. Page 4.9.13 of the DEIR (bottom of page) is hereby amended with the following new paragraphs:

> <u>A Phase II Environmental Site Assessment (ESA) was performed by Fluor Daniel GTI at Pacific Gas and Electric Company's (PG&E) Geysers Power Plant (GPP). The purpose and objectives of the Phase II ESA were:</u>
>
> - <u>to conduct subsurface testing to investigate issues identified in the Phase I ESA and establish a baseline definition of chemical distribution;</u>
> - <u>to present, summarize, and evaluate data collected during the subsurface testing to determine the nature and extent of any impact on soil and groundwater;</u>

- to conduct and present the results of a baseline health risk assessment (BHRA);
- to establish cleanup levels for chemicals which, based on the BHRA and regulatory requirements, are likely to require remediation; and
- to develop a reasonable approach for conducting any required remediation and estimate the costs that would be incurred if the approach were implemented. A reasonable approach is defined as a cost effective approach having a high likelihood of being accepted by regulatory agencies having jurisdiction over the remediation process.

Fluor Daniel prepared a soil and groundwater sampling plan for the site; a summary of the work that was completed during the Phase II subsurface testing is provided below.

Subsurface Testing Completed between January and July 1998:

- drilled 347 soil borings, including hand augured borings;
- collected and analyzed 927 soil samples;
- installed 36 temporary groundwater monitoring wells;
- collected and analyzed 76 groundwater samples from 36 newly installed temporary wells and 11 existing permanent monitoring wells; and
- measured liquid levels in all wells.

The data at the Geysers Power Plant during the Phase II subsurface testing were used to further describe the site characteristics and to describe the nature and extent of chemicals in soil and groundwater. A summary of results of the Phase II investigations follows.

Soil Results:

- Volatile Organic Compounds (VOCs). The only VOC detected in soil was methylene chloride, which is a suspected laboratory contaminant.
- Polynuclear Aromatic Hydrocarbons (PAHs). PAHs were present in 14 percent of the samples: PAHs were most often detected in the 0- to 1-foot soil zone; the maximum concentrations ranged from a low of 0.22 mg/kg for anthracene at the General Construction Warehouse, to a high of 1.3 mg/kg for acenaphthene and pyrene (each) at the Scrap and Turbine Yard. The average concentration at the 95% upper confidence limit (UCL) for acenaphthene and pyrene were 0.07 mg/kg and 0.073 mg/kg, respectively.
- Polychlorinated Biphenyls (PCBs). PCBs were detected in 4 percent of the samples collected; the maximum concentration was 8.4 mg/kg at Unit 5/6 and the average concentration at the 95% UCL was 0.15 mg/kg.

- Total Extractable Hydrocarbons (TEH). TEH was detected in 88 percent of the samples. The maximum TEH concentration was 19,000 mg/kg at 3.5 ft. at Former Unit 15; however, the majority of the samples are far below this maximum value. The average TEH concentration at the 95% UCL was 193 mg/kg.

- Metals. Various metals were detected throughout the Geysers Power Plant (as expected based on the bedrock geology and natural geothermal conditions); a comparison of metals results to background conditions indicates the metals are naturally occurring in soil and bedrock.

- Asbestos. No asbestos was detected or observed.

Groundwater results:

- Separate-phase hydrocarbon petroleum product. SPH products were observed at three locations: Units 7/8, 9/10, and 14.

- VOCs. VOCs were detected in 22 percent of the samples. The highest concentration was 190 µg/L of 1,1-DCA at Unit 7/8.

- TEH. Hydrocarbons were detected in 28 percent of the samples; the highest concentration was 560,000 µg/L at Unit 7/8.

- PAHs. PAHs were detected in 2 percent of the samples; the highest concentration was naphthalene at 15 µg/L at Unit 9/10.

- Metals. Various metals were detected in the groundwater. The concentrations of metals varied throughout the Geysers area as influenced by varying soil and bedrock geochemistry. The mechanism for their presence in groundwater was generally defined as dissolution of naturally occurring metals from soil and/or bedrock, although at five investigation areas (Unit 5/6, 7/8, 9/10, 11 and former Unit 15) the metals in groundwater may be due to potential contaminant sources.

- PCBs. No PCBs were detected in the 29 groundwater samples analyzed.

A baseline health risk assessment was completed to determine whether the chemicals detected in soil and groundwater present an unacceptable risk to human health and the environment given the assumptions made for the risk assessment. The acceptable level of risk established for this project was consistent with that typically allowed by state and federal environmental agencies, as follows:

(a) For cancer-causing chemicals (carcinogens): a cumulative (i.e. the sum of risks posed by all chemicals) incidental increase in risk to human health no exceeding 1 in 100,000.

(b) For chemicals having other toxic effects (noncarcinogens): a cumulative toxic effect not having a hazard index exceeding 1.0.

Health risks were calculated for potential receptor populations including the current and hypothetical future power plant worker, the current and hypothetical future construction worker, the current and hypothetical future visitor (includes vendors providing deliveries, trespassers and land owners using the area for recreation purposes), the hypothetical future office worker, and the hypothetical future resident.

The risk assessment showed there to be risks to the hypothetical future resident exceeding the project threshold at several investigation areas. The calculated cumulative risk (the sum of risk posed by all chemicals) exceeded the project thresholds for: (1) PCBs and PAHs in soil at Unit 5/6; (2) benzo(a)pyrene in groundwater at Unit 14; and (3) metals in groundwater at several investigation areas (Unit 5/6, 7/8, 9/10, 11, and Former Unit 150.

Risk-based cleanup goals were calculated for boron and vanadium in groundwater. Cleanup goals established in environmental laws and regulations and in previous restoration projects approved by environmental agencies having jurisdiction over the Geysers Power Plant were used for PCBs, PAHs, and other metals.

Cleanup goals for soils were established as follows:

- 100 mg/kg TEH where shallow groundwater was encountered. This value was selected on the basis of a review of cleanup levels approved by regulatory agencies for restoration of former Unit 1-2 and 3-4 at the Geysers Power Plant.
- 1,000 mg/kg TEH where groundwater is not encountered. This level is based on industry and regulatory standards.
- 1.0 mg/kg total PCBs (dry weight). This goal is based on federal regulation regarding PCB wastes.

Cleanup goals for groundwater were established as follows:

- 100 µg/L TEH. This value was selected on the basis of a taste and odor threshold established for diesel in water.
- MCLs for other VOCs, PAHs and metals. The maximum contaminant levels were taken from state and federal regulations regarding beneficial use designations and drinking water standards.
- 980 µg/L and 80 µg/L for boron and vanadium, respectively. These are calculated risk values based cleanup goals protective of human health for drinking water uses (MCLs do not exist for these two compounds).

The data collected during the Phase II investigation were compared against the hypothetical cleanup goals listed above. On that basis, Fluor Daniel GTI postulated that the following site conditions exist for which a regulatory agency would likely require remediation on the basis of the various cleanup goals listed above:

- PCBs in soil: remediation of PCBs in soil at Unit 5/6 where the total PCB concentrations exceed 1.0 mg/kg.

- TEH in soils at sites with shallow groundwater: remediation of petroleum hydrocarbons in soil at locations where concentrations exceed 100 mg/kg TEH.

- TEH in soil at sites with deep groundwater: remediation of petroleum hydrocarbons in soil at locations where concentrations exceed 1,000 mg/kg TEH.

- Separate phase hydrocarbon petroleum product: remediation of floating petroleum hydrocarbons in groundwater where present in measurable thickness.

- TEH in groundwater: remediation of dissolved TEH in groundwater where present in concentrations exceeding 100 µg/L TEH.

- VOC, PAHs, and metals in groundwater: remediation of dissolved organic compounds in groundwater where present in concentrations exceeding MCLs (or risk-based goals for boron and vanadium).

Fluor Daniel GTI suggested various remediation approaches for the contaminants. The alternatives were evaluated and ranked according to their effectiveness, their ease of implementation, and their cost. On the basis of the evaluation and ranking, the highest ranking remedial alternative for each remedial issue was called out as the preferred alternative. The actual remedial steps to be taken ultimately will be decided with the participation of the lead agency.

The findings and conclusions of the Phase II investigation and the Risk Assessment do not modify the analysis nor conclusions of the DEIR.

In addition, page 4.9-25 of the DEIR is hereby amended with the following additional reference:

Fluor Daniel GTI, *Phase II Environmental Site Assessment: Geysers Power Plant*, prepared for Pacific Gas and Electric Company, San Francisco, California, August 1998.

T11 No EIR mitigation measures refer to decommissioning of the units. Regarding decommissioning generally, please see response to Comment B5.

T12 Page 1-7, item No. 4 of the DEIR lists concerns raised by the public with respect to the project prior to publication of the DEIR; no analysis or conclusions of environmental effects are presented in this section. Although there currently are diversions of some creeks by steamfield owners (not owners of generating units) for reinjection, there is no evidence that new owners of the generating units would attempt additional creek diversions, and no diversions are proposed as part of the project. Also see response to Comment N19.

T13 Please see response to Comment B5.

T14 The statement on page 2-38 of the DEIR (third paragraph) that "geothermal steam is expanded through a steam turbine and cooled and condensed into water..." accurately describes the overall electricity-generating process at the Geysers Power Plant. Steam condensate is produced during normal turbine operation. There is no reason to believe that divestiture would result in increased amounts of steam condensate being generated at the plant. See the responses to Comments H4, H5, and H15 for discussions of market forces and related factors that might affect future utilization of the Geysers steam resources.

Trace chemical constituents of geothermal steam were discussed in the DEIR in Section 4.9, Hazards. Toxic properties of the trace constituents of steam reflect the natural properties of local geology. There is no information to support the commenter's contention that steam contains a "vast number of toxic substances" that the "original permit granters were afraid to ship...over the highways of California."

Hazardous waste streams at the Geysers Power Plant generally are process wastes associated with abatement systems; these wastes are handled in proper fashion, as is described in detail in the DEIR on page 4.9-23 under Impact 4.9-5, and on page E-5 of Attachment E.

The most significant toxic component found in the naturally occurring geothermal steam is hydrogen sulfide gas, as is discussed in the DEIR on page 4.9-12. All of the generating units at the Geysers Power Plant have hydrogen sulfide abatement systems, as is mentioned on page 4.9-12 and described in more detail in Attachment E in the DEIR. Also see response to Comment H22.

Other naturally occurring trace contaminants of geothermal steam include mercury and arsenic, as is mentioned on page 4.9-13 in the DEIR. Mercury is removed from the geothermal steam by means of activated-carbon scrubbers, as is described in the DEIR on page 4.9-13 (second paragraph). Precautions taken to minimize exposure to other metals including arsenic are described in the response to Comment H47.

T15 Please see response to Comment B5 regarding increased risk of environmental impact under a new owner in relation to plant decommissioning. The potential impacts of future decommissioning (not a part of divestiture) of the sulfur scrubbing units would not be affected by plant ownership, nor by the type of sulfur scrubbing technology employed at various Geysers units. The commenter offers no rationale for why decommissioning of the various scrubber systems might pose any unusual environmental problems.

Refer to the response to Comment H31 for a discussion of best available control technology for hydrogen sulfide at the Geysers units. Refer to the response to Comment H22 for an expanded description of sulfur scrubbing systems.

T16 The commenter notes that a representative wind rose was not presented for the Geysers Power Plant similar to those provided for the three Bay Area power plants, and assumes that such data were unavailable to the DEIR preparation team. In fact, tabular wind speed and direction data from several locations within the Geysers area were available to the DEIR authors during report preparation. These data were reviewed and considered as part of the environmental review for air quality impacts. They were not presented in the DEIR because the Geysers units, unlike each of the fossil-fueled plants, are located in a mountainous region with units widely separated by distance, elevation, and terrain. The several available meteorological data sets examined for the Geysers each tended to show influences from local topography specific to the location of the Geyser unit closest to that monitoring station. Because of these local influences, none of the available meteorological data sets could be considered representative for the all of the Geyser units and, thus, were not presented in the DEIR. The local wind flow situation present in the Geysers area is further discussed on the final paragraph of page 4.5-2 and the first full paragraph of page 4.5-3 of the DEIR.

T17 The decline in the Geysers steam field production has been known since at least 1987. Both steam field and power plant operators have studied various means of extending the steam supply, including closing power plants. Based on the analysis presented in the DEIR, divestiture of the Geysers is unlikely to exacerbate the steam field decline. For this reason, analysis of “productivity and potential shutdown of certain plants” is inappropriate given the lack of any discernible causation.

Alternative 3 (sale of Geysers units to the steam field owners) is designated the “environmentally superior alternative” because it would “unify” the steam fields to a large extent by vertically integrating the operations (see page 6-23 of the DEIR). This would improve the incentives to effectively coordinate steam and electricity production to maximize the economic benefits from Geysers generation.

T18 The runoff from the plants at the Geysers is contained through on-site drainage facilities and injected to supplement the natural deep groundwater and increase steam production.

The DEIR page 4.3-6 has been revised in response to Comment H27 to list serpentine as part of the geologic structure of the Franciscan Formation that underlies the Geysers. As noted in response to Comment H27, in order for asbestos particles that are contained in the serpentine rock to become a hazard, it would have to be entrained into the air and transported by the wind to offsite receptors. For this to occur, the exposed rock would have to be crushed through construction activities and clearing and grading operations. The project will not require construction operations at the Geysers plant. Therefore there would be no exposure to asbestos particles under divestiture.

With respect to the area’s mercury mines, page 4.3-6, paragraph 2 is hereby revised to add the following language at the end of the paragraph:

Several abandoned mercury mines are located within the Geysers area, including Big Chief Mine, Thorne Mine, and Big Injun Mine which are located within ¾ mile from Unit 16. Soil samples from the area near Unit 16 were collected and analyzed as part of the Phase II Environmental Site Assessment (Flour Daniel GTI, 1998). Mercury levels in the soil samples were found to be within background levels.

September 21, 1998

Mr. Bruce Kaneshiro, Project Manager
c/o Environmental Science Associates
225 Bush Street, Suite 1700
San Francisco, CA 94104

Re: Pacific Gas and Electric Company's Application for Authorization to Sell Certain Generating Plants and Related Assets, Application No. No. 98-01-008, Draft Environmental Impact Report ("DEIR")

Dear Mr. Kaneshiro:

The Environmental Law and Justice Clinic submits the following comments on the above-described DEIR on behalf of the Southeast Alliance for Environmental Justice (SAEJ).

Part I. General Comments

[Begin U1]

While the DEIR has presented much useful information, it nevertheless contains several fundamental errors prohibited by CEQA and undisputed case law. The major error is the DEIR's various methods for minimizing the impact from the potential increased air pollution that may result from the sale of the facilities over the next few years. The San Francisco Bay Area ("Bay Area") during the winter months is routinely in violation of the state's particulate (PM10) standard, meaning that thousands already are suffering early deaths or asthma and emphysema exacerbations as a result of PM10 exposure. In the summer months, the Bay Area routinely violates the state ozone standard and occasionally the federal ozone standard, resulting in the area being designated a nonattainment area by state and federal air quality agencies. At the same time, there is no state PM10 attainment plan in place, the state ozone plan makes no pretense of assuring attainment by any date certain, and the US EPA has determined the federal maintenance plan is now inadequate to attain the federal ozone standard. Thus it is crucial that this project not contribute to existing air quality conditions or delay the attainment of these standards.

[End U1]

[Begin U2]

The DEIR discloses that particulate matter and smog precursors (nitrogen oxides and reactive organics) emitted from Bay Area power plants may about double as a result of the sale in 1999. Table 4.5-26 at p. 4.5-57. Yet it dismisses the impacts from these increased pollutants in various spurious ways that amounts to saying the difference is tiny compared to the amount of pollution already in the air. This "ratio" approach, whether thought of a significance threshold or a qualitative evaluation, is illegal when applied to cumulative impacts at the EIR stage and inappropriately discounts the importance of those bearing the burden of the resulting significant

health impacts. See Los Angeles Unified School District v. Los Angeles, 58 Cal. App. 1019, 1025 (4th Dist. 1997); Kings County Farm Bureau v. City of Hanford, 221 Cal. App. 3d. 692 (5th Dist. 1990).
[End U2]

[Begin U3]
Another error in the DEIR is its failure to provide a proper comparison between the baseline and the impact of the sale so that the full extent of any potential adverse impacts are captured and mitigated. The DEIR picks 1999 as the first year for comparison, an appropriate step to take. However, the DEIR then jumps to 2005 for its cumulative analysis because more stringent air quality impacts are then in place and PG&E's operating characteristics are assumed to be quite similar to any other owner. It ignores the years 2000 (with one exception), 2001, 2002, 2003 and 2004. SAEJ believes this approach is wrong because it ignores potentially greater cumulative impacts in years after 1999 and before 2005 due to increased energy demand resulting from deregulation and growth, and fails to acknowledge the continued differences that may occur between PG&E and third party ownership even into the year 2005 due to PG&E's remaining portfolio of facilities. See p. 3-7 and Attachment C.
[End U3]

[Begin U4]
Another error was to use the SERASYM model to produce analytical maximum capacity factors far below 100%. See Table 3.1 at p. 3-10. While the SERASYM model is a good predictor depending upon the inputs, its results are not enforceable. If the circumstances affecting these inputs change, e.g. natural gas prices, transmission system capability, operating procedures, capacity could rise approaching their theoretical capacity. Unless the project approval contains conditions limiting the project to the capacity factors predicted in this SERASYM run, the CEQA analysis has failed to properly analyze the potential extent of adverse impacts.
[End U4]

[Begin U5]
As a result of reviewing the DEIR and SAEJ's own analysis, SAEJ believes it is imperative that mitigation be required for this project. The mitigation could be requiring BACT for all Bay Area power plants, with sufficient offsets to eliminate any contribution to cumulative impacts. Or it could be a condition limiting capacity to that which would have forseeably occurred under SERASYM's analysis if PG&E retained ownership. Only with these conditions could the project then said to be without significant impacts.
[End U5]

Specific Comments

I. SIGNIFICANCE CRITERIA FOR AIR QUALITY

The DEIR lists its air quality criteria at pp. 4.5-50 through 4.5-51. The criteria mainly relied upon are criteria 1,4 and 5. SAEJ believes these criteria are in many respects technically inappropriate and illegal.

A. Criterion 1

[Begin U6]

The first criterion states that violation of an ambient air quality standard or substantial contribution to a projected violation of an ambient air quality standard requires a finding of significance. This is appropriate for a project specific impact. See Appendix G. However, it is inappropriate when evaluating cumulative impacts once an EIR is underway:

> There appears to be a difference between the "cumulative impacts" analysis required in an EIR and the question of whether a project's impacts are "cumulatively considerable" for purposes of determining whether an EIR must be
> prepared at all. For purposes of an EIR, the Guidelines define the 'cumulative impact' from several projects as the change in the environment that results from the incremental impact of a project when added to other past, present, and reasonably foreseeable future projects. 14 Cal Code Regs @ 15355." 1 Kostka & Zischke, Practice Under the Cal. Environmental Quality Act, @ 6.55, pp. 298-299, (quoted in San Joaquin Raptor/Wildlife Rescue Center v. County of Stanislaus, 42 Cal. App. 4th 608, 623 (5th Dist. 1996)).

The DEIR should make clear that this criterion is inapplicable to cumulative impacts, and the cumulative analysis as discussed below needs to conform to the EIR version of a cumulative impacts analysis.

[End U6]

[Begin U7]

The first criterion goes on to define "substantial" for this project based upon the PSD provisions in the BAAQMD rules in Regulation 2, Rule 2. For example, the PM10 criterion would require a 5 microgram/cubic meter for a 24 hour average increment and a 1 ug/m3 for an annual average.

In fact, PSD refers generally to maintaining a standard already attained and the BAAQMD rules specifically reference federal requirements applicable to maintaining federal standards in attainment area. For this project, the ambient environment is a nonattainment area for federal ozone, state ozone and state particulate matter (PM10). The criterion ignores the provisions of Regulation 2, Rule 2, that includes the use of BACT and offsets to assure that standards are attained.

CEQA does not allow a part of a standard to be borrowed and used in a manner not used by the agency adopting the standard. A standard includes the quantitative, qualitative or performance requirement found in a statute, ordinance, resolution, rule, regulation, order, or other standard of general application. CEQA Guideline Section 15064 (i)(3)(A) as amended August 24, 1998. Thus BACT and offsets cannot be eliminated. The standard must govern the same environmental effect which the change in the environment is impacting. 15064(i)(3)(D). That would only work here if BACT and offsets are applied. This criterion is just not appropriate without the entire standard as applied by the BAAQMD.
[End U7]

B. <u>Criterion 4</u>

[Begin U8]
Criterion 4 asserts that based upon its review of PM2.5 studies that a significance threshold of 20 ug/m3 is appropriate for short term exposure. On an annual basis, an increase must be 10 ug/m3. The criterion is based upon the DEIR's understanding of an EPA report, a number of health studies, and a private conversation with one of the authors of one of the reports.

This criterion as discussed below under cumulative impacts is not appropriate for evaluating cumulative impacts. As to project specific impacts, the DEIR also seems to have a serious misunderstanding of this literature. The EPA report makes clear it was unable to determine any safe threshold for increases in PM10. In fact, the EPA reviews many of the same studies described in the DEIR and presents graphs and narrative showing near linear increases in PM impacts at all measured levels. The report further asserts that once a certain level in the ambient environment is reached (significantly below the standard), increases in pollution produce clear and consistent increases in risk of health impacts. The EPA found no significant difference in this regard between studies for PM10 and PM2.5.

According to the survey of health studies conducted by the City and County of San Francisco Department of Public Health (DEP), any increase in particulate matter may cause health effects. 11/27/95 DEP letter to CEC, attached hereto as Exhibit A. This is particularly true in this case, where the state PM10 standard is often exceeded during winter months in San Francisco and the rest of the San Francisco Bay Area. A DEP survey report on particulate matter health effects studies indicate that "there is no lower threshold below which...problems do not occur" and that "these effects occur at levels well below the current federal standards for PM10 pollution." Exhibit A at 2.

These studies are epidemiological studies, and for methodological purposes, have used incremental increases of 10 ug/m3 in order to clearly identify differences in health effects that are due to particulate matter and not other confounding factors.. The DEIR seems to confuse these increments as increments of significance, rather than as methodological tools. The key for

development of a significance factor is that when these increments are plotted from various studies they show a near linear increase. There is no scientific evidence, and no expert of any repute, who is claiming that health effects jump from one data point to another, as if there is a step graph of results.[1] The DEIR appears to misinterpret the private communication with N. Schwartz in that he has conducted a study where the data points were interpreted at 10ug/m3, not that an increase of 5ug/m3 would not produce any impacts or that there is no linear increase. The DEIR seems confused about the meaning of the studies.
[End U8]

[Begin U9]
An additional study by G.D.Thurston, summarized in the documents attached hereto as Exhibit B, suggests that PM10 impacts may even be more severe in San Francisco than in other locations in the country, although its ambient level is lower. Thurston, the author of 5 other studies relied upon by the DEIR, see pp. 4.5-83 through 4.5-84, suggested that residents rely less upon air conditioning in San Francisco than in other hotter communities, and therefore are more exposed to the PM10, thereby increasing the impact from the level of exposure. The DEIR should take account of this study and adjust its notion of significance accordingly.[2]
[End U9]

[Begin U10]
This San Francisco vulnerability is even more important for the Bayview-Hunters Point community. Impacts from PM10 (as well as ozone) are especially important since residents of this part of San Francisco have high incidences of chronic lung disease, including asthma, emphysema and bronchitis. Inhalers are more often prescribed at the Southeast Health clinic than at any other. The most common reason for visits to the Clinic is respiratory symptoms. See Exhibit at 4. The DEIR should take into consideration the greater vulnerability of this population to additional pollution or a delay in attaining air quality standards. This vulnerability also includes a lack of access to medical care and the other complications of poverty that aggravate the impact of disease. According to the CEQA Guideline 15064(b), “An ironclad definition of significant effect is not always possible because the significance of an activity may vary with the setting. For example, an activity which may not be significant in an urban area may be significant in a rural area.” In this case, it is the particular urban area impacted which must change the significance criteria.
[End U10]

1 As three leading PM researchers put it, when evaluating the major studies that had been conducted, “There is no clear evidence of a safe threshold level. Many studies observe that health effects increase monitonically with pollution levels, often with a near-linear dose-response relationship.” C. Arden Pope III, David V. Bates, and Mark E. Raizenne, “Health Effects of Particulate Air Pollution: Time for Reassessment?”, Environmental Health Perspectives, Volume 103, Number 5, May, 1995, pp. 472 et seq. at 478-479.

2 It is also likely that smaller changes in concentration of PM2.5 are more profound than with PM10 as PM2.5 particles are smaller and therefore the number of particles are greater per unit change in concentration, suggesting that any increment should be far less than it is for PM10. The number of particles penetrating deeply into the lung may be the crucial mechanism leading to the inflammation causing PM impacts. See Bart Ostro, “The Association of Air Pollution and Mortality: Examining the Case for Inference”, Archives of Environmental Health,, September/October 1993 [Vol. 48(No. 5)], pp. 336 et seq. at 341.

[Begin U11]

The problem with the thresholds utilized is best revealed by analyzing the actual health impacts resulting from the increases projected to result from the project. According to Table 4.5-26, the increase in PM10 from the PG&E proposed project to sell the three fossil fuel San Francisco Bay Area power plants is from 297 to 345 tons per year, looking just at the years 1999 and 2005. According to the testimony of the Bay Area Air Quality Management District's chief statistician, Dr. David Fairly, in the prior San Francisco Energy Company application before the California Energy Commission, attached hereto as Exhibit C, an increase from a proposed power plant in Hunters Point of more than 45 tons per year in PM (as with this plant, primarily PM2.5) could have resulted in 2-6 deaths in the region, with a far greater number of incidents of asthma and emphysema exacerbations. Exhibit C at 6. Using these numbers, one could project that the number of deaths would accordingly increase for the entire PG&E power plant sale, as 345 tons would result in 15 to 46 deaths per year, with still greater numbers of incidents of asthma and emphysema exacerbations. Yet the DEIR's threshold implicitly suggests inhumanely that this number of deaths of people is insignificant, as well as the suffering from emphysema and asthma that would affect far more people than those whose deaths are hastened by the PM10 exposures, because the concentration level does not rise to the 10ug/m3 used for methodological purposes in epidemiological studies.

[End U11]

[Begin U12]

The DEIR in addressing a situation where the standards are already exceeded should be consistent with the good science suggested by the City's Public Health Department and the expert scientific opinion of the BAAQMD's statistician. Any increase that may impact a human being and cause a serious health impact such as death, asthma attack or emphysema is significant, and should require the source to utilize BACT offset increased emissions.

[End U12]

C. <u>Criterion 5.</u>

[Begin U13]

Criterion 5 declares that inconsistency with the regional air quality plan is a basis for the finding of significance. While the current plans are insufficient to attain health standards, certainly a conflict with such a plan would suggest a significant impact.

The problem with the criterion is that it goes on to create a threshold whereby inconsistency must cause an increase over one percent of the regional inventory. It is not clear where this criterion comes from.

As discussed below regarding cumulative impacts, this use of a ratio is not appropriate when evaluating cumulative impact. This criterion is also faulty because the Bay Area plan assumed that the federal standard was maintained, and the state standard does not guarantee

attainment by any date certain. In such circumstances, any violation of the plan has serious repercussions.
[End U13]

II. CUMULATIVE IMPACTS

[Begin U14]
The DEIR tries to dismiss cumulative air quality impacts (as well as other air pollutant impacts) by relying on the judicially discredited ratio analysis. The DEIR basically argues that since the percentage of air quality emissions and the accompanying concentrations from the plants are small compared to the Bay Area inventory and accompanying concentrations, then the increase is insignificant. The DEIR also uses the years 2005 and 2015 for its cumulative analysis, and wrongly limits cumulative impacts in many instances to future project or a limited set of existing projects, rather than all past, present and reasonably anticipated future projects impacting the ambient air.

The relevant question to be addressed is not the relative amount pollutant from the project when compared to existing pollution but whether an additional amount should be considered significant in light of the serious nature of the already existing problem. Los Angeles Unified School District v. Los Angeles, 58 Cal. App. 1019, 1025 (4th Dist. 1997). In that case, the court determined that the EIR was inadequate because it deemed insignificant an expected 2.83 dBA increase in noise from the proposed project because it failed to meet a regulatory significance threshold, even though the noise level in the area already exceeded the State's recommended maximum of 70 dBA. A similar reasoning is present in this DEIR.

In determining the cumulative effects of the increase in carbon monoxide, reactive organic gases, nitrogen oxides, and particulate matter, the DEIR reports that the increases are less then significant because the power plants will not contribute more than 1% of these pollutants to the region's air quality in the years 2005 and 2015. See Pg 4.5-59 and Table 4.5-26 at 4.5-57. However, at the same time the amount of regional carbon monoxide will increase by 2,275 tons/yr, ROGs 322 tons/yr, SOx 84 tons/yr, and PM-10 297 tons/yr. NOx will be reduced by controls finally in effect by 2005, but in the 1st year after the sale NOx will increase by 4,389 tons/yr.

A project's impact cannot be considered insignificant because it's contribution to air quality is insignificant when compared to other sources. Kings County Farm Bureau v. City of Hanford 221 Cal. App.3d 692, 720 (5th Dist. 1990). The Court of Appeals held inadequate the cumulative impact analysis prepared for an EIR for a proposed coal-fired cogeneration power plant. The Court called this method of finding an impact insignificant because it was small compared to other sources, the incorrect approach. Id. This "ratio" theory of impact analysis allows a large pollution problem to make a project's contribution appear less significant in a cumulative impact analysis. But the Court strongly disagreed, holding that such a method would "avoid analyzing the severity of the problem and allow approval of projects which, when taken in isolation, appear insignificant, but when viewed together, appear startling." It is invalid and

terribly misleading of the DEIR to conclude that the impacts to air quality are insignificant because it is less then one percent of regional emissions. (Pg 4.5-59). In fact, the more severe existing environmental problems are, the lower the threshold should be for treating a project's cumulative impacts as significant. Id. at 721. See discussion of Los Angeles Unified School District v. Los Angeles (1997) 58 Cal. App. 1019, supra.
[End U14]

[Begin U15]
Utilizing Dr. Fairly's analysis described above makes clear how inhumane this ratio approach is. As discussed above, Dr. Fairly's analysis would estimate approximately 15-46 deaths from the entire proposed project. Dr. Fairly also concluded that approximately 1,260 to 2,940 deaths per year are attributable to PM10 exceedances of the state standard in the Bay Area. Exhibit C at 7. The ratio approach might basically suggest that if 15 deaths is the more accurate number, and 2,940 is more accurate for the region, since 15 deaths are less than 1% of the region, these 15 deaths are insignificant and no effort should be made to avoid these deaths. This kind of analysis is immoral, and illegal under CEQA, whether we are talking about deaths, asthma attacks, exacerbations of emphysema or heart disease, all impacts associated with PM.
[End U15]

[Begin U16]
The appropriate test for cumulative impacts requires first examining whether a standard is exceeded in the ambient atmosphere at any time during the life of the project. In this case, that is true for PM10 and ozone at least in the foreseeable future. The DEIR properly notes that both ozone and PM10 standards are now being violated, and should also note that no plan for attainment of the state PM10 standard is in place, the federal plan for ozone has been found to be inadequate to attain the standard, and the state ozone plan does not provide for attainment of the state ozone standard by any date certain.[3] The next question is whether power plant emissions contribute pollutants regulated by the standard to the ambient atmosphere. As the DEIR correctly points out, that is true for all facilities. E.g., p. 4.5-26 (For Potrero - "The power plant emissions contribute to ambient pollutant concentrations of criteria air pollutants in the plant vicinity"). If so, the cumulative impact must be considered significant. See discussion under criterion 1, above.[4]
[End U16]

III. CAPACITY FACTORS

[Begin U17]
The DEIR attempts to evaluate the potential extent of impacts by using a SERASYM model based upon an estimate of the likely operations of the new facilities, rather than their true

3 The DEIR should make clear that US EPA's action designating the area as nonattainment also found the existing maintenance plan inadequate and is requiring the District to develop a new plan.

4 It might be useful for Potrero to break the wind rose down by months. If so, as with the Hunters Point assessment performed by the California Energy Commission, it would show that during winter months when PM10 levels are high in the community, the wind is more often blowing into the community bringing power plant emissions with it.

potential maximum capacity. Such an analysis hardly evaluates the potential adverse impacts that could result from the sale. Much of the analysis of impacts assumes that the new owners will operate the Potrero plant, for example, at the Analytical Maximum Capacity of 44% in 1999 and 40% in 2005. (pg 3-10). However, the DEIR states that "the degree to which generation would increase at the plants slated for divestiture is highly uncertain." (pg 3-8). Given this uncertain nature, it is imperative that the DEIR examine how the change in degree of generation will affect pollution output at capacity factors greater than 44% and 40% and determine at what point the degree of generation will result in significant impacts. [End U17] [Begin U18] Since energy output is not constant throughout the year (pg 4.5-22), the DEIR should also provide information on the actual maximum capacity factor on a daily basis and how that would differ from the annual capacity factors. [End U18]

[Begin U19]

Additionally, the DEIR does not contain facts and analysis to show how the various capacity factors were derived other than to describe in general terms the major assumptions that were used in the baseline computer simulation. (pg 3-9). "The EIR must contain facts and analysis, not just the bare conclusions of a public agency. An agency's opinion concerning matters within its expertise is of obvious value, but the public and decision-makers, for whom the EIR is prepared, should also have before them the basis for that opinion so as to enable them to make an independent, reasoned judgement." Santiago Water District v. County of Orange, 118 Cal. App. 3d 818, 831 (4th dist. 1981). "[A]n EIR must include detail sufficient to enable those who did not participate in its preparation to understand and to consider meaningfully the issues raised by the proposed project." Laurel Heights Improvement Association v. Regents of the University of California, 47 Cal. 3d. 376 (1988).

[End U19]

[Begin U20]

If the EIR is assuming the maximum capacity is 44%, it is incumbent that the project description and the Commission's approval include a condition that the plant cannot be operated at a capacity factor at any time (at least over a 24 hour period to reflect the PM10 24 hour standard) over 44%. Otherwise the analysis fails to consider the potential adverse impacts from this sale and an approval for operations at greater capacity would not be supported by the environmental analysis.

[End U20]

IV. THE AIR QUALITY BASELINE AT POTRERO NEEDS FURTHER ANALYSIS.

[Begin U21]

The DEIR fails to provide needed data on the air quality baseline in the vicinity of the Potrero Power Plant. In preparing an EIR, the project's impacts must be evaluated against the backdrop of the "environment." CEQA Guidelines §15063. CEQA Guidelines define the "environment" as the "physical conditions which exist within the area" including "both natural and man-made conditions." CEQA Guidelines §15360. An EIR must describe "the environment in the vicinity of the project as it exists before the commencement of the project, from both a local and regional perspective." CEQA Guidelines §15125. No air quality data is presented for the local vicinity of the Potrero Plant. In fact, the only baseline air quality data presented is for the Arkansas Street Monitoring Station, which is over 1 mile away and predominately upwind or cross wind from the Potrero Plant. (pg 4.5-22) Conversely, no information is presented that would suggest a correlation or relationship between air quality at the Arkansas Street Monitoring Station and air pollutants released from the Potrero Plant. In fact, the DEIR suggests no correlation or relationship exits between air quality at the Monitoring Station and the Potrero Plant, given that the highest PM10 concentrations measured at the Monitoring Station do not correspond to the time of year of the highest PM10 releases from the Potrero Plant. (pg 4.5-22). Or conversely, it could be interpreted that if PM10 is high in the winter when emission are blowing toward the monitoring station then they may be even higher during times of the year that power generation is higher and therefore PM10 emissions are higher. Monitoring data from Table 4.5-7 (pg 4.5-23) is from the Arkansas Street Station, which, if interpreted with the wind rose presented on page 4.5-27, most likely represents air quality from areas at least 3/4 mile west of the Potrero Power Plant, such as the Mission District and US 101 Freeway.

The DEIR needs to explain the relationship between the monitoring station and modeling results and justify the relevance of comparing modeling results with the ambient air quality data from the Arkansas Street Monitoring Station. In addition, the DEIR needs to demonstrate how the ambient air quality presented in Table 4.5-7, pg 4.5-23 is relevant to stack emissions from the power plant. If a relevance can be established, data should be presented that discloses the ambient air quality during the times that the Arkansas Monitoring Station is downwind of the power plant.
[End U21]

V. SECONDARY PARTICULATE MATTER

[Begin U22]
The DEIR fails to address the generation and impacts of particulate matter formed by the reaction of nitrogen oxides in the atmosphere, known as secondary particulate. It is estimated that up to 1/6 of the nitrogen oxides from power plant emissions are converted to particulate matter (private conversation with David Fairly).
[End U22]

VI. MODELING ANALYSIS

[Begin U23]
The DEIR fails to present sufficient details of the dispersion modeling analysis of PM10 (pg 4.5-31) to allow the public and decision-makers to evaluate the model data imputs, assumptions and findings in order to have some level of confidence in the model's conclusions. [End U23] [Begin U24] For the model to be usable as a way to predict future events it must, at a minimum, be demonstrated that the model can actually predict present effects from present pollution source conditions. In other words, data from actual emissions of the power plant should be used as input data to the model and the model's prediction of pollutant

concentrations at the receptors (where the people are located) should match actual field measurements at those locations. [End U24] [Begin U25] Additionally, it should be demonstrated how changes in model assumptions and changes in input data will effect the output. This is the only way that the results from the model can be considered meaningfully. [End U25]

VII. NOx AND OZONE

[Begin U26]

The DEIR does not adequately address the impact of the project to local and regional ozone concentrations. Table 4.5-26 indicates that ROG and nitrogen oxides will about double in 1999 upon sale of the plants which suggests that ozone concentrations will also increase and that such emissions will be above the baseline (defined as the emissions resulting from PG&E's ownership) until such time as PG&E's operations without a sale would be equivalent to the operations with a sale (this may never be true unless PG&E entirely divested all of its facilities). [End U26]

[Begin U27]

The DEIR appears to dismiss the significance of the project's ozone precursor emissions in two ways. First it notes that the emissions will eventually decrease once more stringent concentration standards are in place. This analysis errs in two respects. First, in years prior to the more stringent limits, emissions will increase. Secondly, even when they decrease, they would decrease even more if PG&E retained ownership. As these are concentration rather than mass limits on emissions, if PG&E operates it less given its likely portfolio of facilities their ownership would mean further reductions. As the region is out of attainment, the failure to grasp additional ozone reduction opportunities may mean a failure to attain the standard, causing a significant impact.

[End U27]

[Begin U28]

The DEIR seems to implicitly rely upon its significance threshold that these emissions will be consistent with the Bay Area SIP. However, the SIP has been determined to be inadequate by the US EPA to attain the standard, thus compliance with Rule 9-11 is no guarantee of avoidance of a significant impact. Until EPA approves a new plan, not expected until at least 2001, any increase in emissions or minimizing of potential reductions due to the sale of the plant may mean significant impacts unnecessarily continue or are exacerbated.

[End U28]

[Begin U29]

As with PM10, the DEIR indulges in a ratio analysis by comparing the increased ozone precursor emissions with the regions ambient ozone concentration. This analysis for the reasons described above is improper. Given that there is no approved plan in effect to attain the federal standard, and the state plan makes no pretense of assuring attainment of the state standard, any

increase in emissions or minimization of reductions resulting from the project will cause cumulative impacts that are significant.
[End U29]

[Begin U30]
During the interim years before the most severe NOx controls begin to be in place (2002), smog exceedances may occur with increasing frequency in the San Francisco Bay Area (1995, 1996 and 1998 smog levels are the highest in a decade). The report should note that US EPA determined that the BAAQMD plan is now insufficient to prevent such exceedances, and that new controls may not be approved by EPA until somewhere between 2000 and 2002. ROG and NOx will about double by the year 2000 as a result of the sales of the power plants. ROG and Nitrogen oxides are precursors to the formation of ozone. Unless emissions from the plants are balanced completely by offsets and the utilization of BACT, the cumulative impact must be considered significant.
[End U30]

VIII. CARBON MONOXIDE AND SULFUR OXIDES

[Begin U31]
Table 4.5-23, pg 4.5-54 indicates that the Potrero emissions of carbon monoxide and sulfur oxides may increase substantially from the 1999 baseline yet Table 4.5-29, pg 4.5-63 indicates no local change in carbon monoxide or sulfur dioxide concentration. That table appears to present conflicting information unless there is a valid reason why stack emissions can increase and have absolutely no affect on the maximum local concentrations of pollutants in the air. [End U31] [Begin U32] Table 4.5-23 also indicates that emissions of nitrogen oxides will double between the 1999 baseline and the 1999 analytical maximum but the local ambient concentration of nitrogen dioxide will remain unchanged (Table 4.5-29). This apparent discrepancy should be explained. [End U32]

IX. TOXICS

[Begin U33]
The DEIR concludes that since project-specific toxic impacts are less then significant cumulative risks are also insignificant. (Pg 4.5-75) This conclusion comes from the conclusion presented in the Mission Bay SEIR, which assumed that cumulative impacts on ambient concentrations of toxic air contaminants are significant since the project-specific impacts are significant. Although it can be conservatively assumed that cumulative risks are significant if the project-specific risks are significant, the reverse is not necessarily true. CEQA Guidelines define a mandatory finding of significance to include where "the project has possible environmental effects which are individually limited but cumulatively considerable." "...cumulative considerable means that the incremental effects of an individual project are considerable when viewed in connection with the effects of past projects, the effects of other current projects, and the effects of probable future projects." (CEQA Guideline 15065(c)). Section 15355 says that "cumulative impacts can result from individually minor but collectively

significant projects taking place over a period of time." The DEIR's reasoning for a finding of no cumulative impacts is therefore illogical and directly contrary to CEQA Guidelines and case law. The DEIR needs to therefore consider in a more realistic approach the cumulative effects of toxic air contaminants.
[End U33]

[Begin U34]
The DEIR concludes that cancer risk is insignificant because the incremental increase in cancer risk is 0.06 per million. (pg 4.5-30) However, there is no standard significance threshold for acceptable cancer health risks. (pg 4.5-30) The predicted increase in cancer risk is also proportional to the increase in energy generation by the new owners, so the actual cancer risk may be higher then stated. Even so, it is necessary under CEQA considerations of cumulative impacts to address the incremental increase of cancer risk increase as cumulatively considerable. The DEIR downplays cancer risk to Bayview-Hunters Point residences by citing a California Department of Health Services report[5] which states that breast cancer rates were "very similar to other regions of the Bay Area." DEIR at 4.5-30 through 31. This may or may not be true since differing conclusions can be drawn depending on which time period for observations is chosen. However, it is of little comfort since Bay Area rates are among the highest in the world, and the Glazer study does not question the Bay Area rates. The DEIR should point out that, according to the American Cancer Society[6]:

1. African American men have the highest overall cancer rate of all ethnic groups in the United States.
2. Hispanic women are nearly twice as likely as the general population to develop cervical cancer.
3. Breast cancer rates among African American and Native American women in the San Francisco Bay Area are among the highest in the world.

Consequently, when the incidences of various forms of cancer in the Bayview-Hunters Point neighborhoods are compared to national averages, and considering the ethnic makup of the neighborhoods, the results demonstrate that cancer is already a serious problem around the Potrero Power Plant and any increase in cancer is significant.
[End U34]

[Begin U35]
Table 4.5-10 displays toxic air contaminants that were emitted up to 1995, and with the exception of benzene and formaldehyde, the 1995 concentrations are "zero or less than reportable quantities." It should first be clarified which of the 1995 concentrations are in fact zero <u>or</u> less than a reportable quantities and, if applicable, what is the reportable quantity. Secondly, the DEIR does not make any prediction or estimation of the amount and

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5 Glazer, Eva R., Martha M. Davis, Tomas Aragon, <u>Cancer Incidence Among Residents of the Bayview-Hunters Point Neighborhood, San Francisco, California, 1993-1995</u>. Prepared by the Cancer Surveillance Section, Department of Health Services, January 1998.

6 Senators Dianne Feinstein and Connie Mack Report to Senate Cancer Coalition. (http://www.senate.gov/~feinstein/cancer2.html, 11/25/97)

concentrations of toxic air contaminants after the Potroro Plant is sold. At a minimum, Table 4.5-10 suggests that benzene and formaldehyde, both human carcinogens, will continue to be emitted after the power plant is sold and that the amounts will probably increase in proportion to the amount of electricity generated. The DEIR needs to specifically address these chemicals, considering the amounts emitted and dispersion pattern, both temporally and spacially.
[End U35]

X. LOCATION OF NEW GENERATION

[Begin U36]
Table 5.1 (pg 5-12) and Section 5.3 (pg 5-16) do not include the strong possibility of a power generation facility being built next to the Potrero Power Plant and/or the repowering of the Potrero Power Plant. The DEIR reports that power demand in San Francisco will increase by approximately 10 MW per year and that the Hunter's Point Plant will be closed when replacement power generating capacity is available and that it is necessary that new generating capacity be located north of the Martin Substation. (Citation) The Potrero Plant is located in an M-2 (heavy industry) District zone and it is our assumption that any new generating facility will be similarly zoned. Given the increased demand for electricity, coupled with the limited number of M-2 zones north of the Martin Substation it is reasonably foreseeable that a new facility may be located next the existing Potrero Power Plant and/or there will be some economic incentives to repower the Potrero Plant.
[End U36]

[Begin U37]
Further, DEIR states in Attachment C (System Economics and Operational Characterization) that "a new owner may repower as soon as possible to reduce the potential economic benefits to the ISO from approving a transmission upgrade." (Pg C-36) In other words, there is a foreseeable economic advantage to repowering the Potrero Plant. Impact assessments should account for reasonably foreseeable future phases, or other reasonably foreseeable consequences, of proposed projects. Laurel Heights Improvement Association of San Francisco, Inc. v. Regents of the University of California, 47 Cal.3d. 376 393 (1988). The Court in Laurel Heights reasoned that even though a future expansion of a medical facility was not yet formally approved, the expansion was reasonably foreseeable. In a separate case the California Fish and Game Commission had to assess the cumulative impacts of authorizing mountain lion hunting on future hunting seasons, even though separate future regulatory decisions would be required to approve such seasons. Mountain Lion Coalition v. California Fish and Game Commission, 214 Cal. App.3d 1043, 1048 (1st Dist. 1989). The DEIR must therefore anticipate that repowering will take place and/or that additional generating capacity could be built next to the Potrero Plant.
[End U37]

XI. IMPACTS TO WATER QUALITY

[Begin U38]

The DEIR declined to find a significant impact to surface water quality, using future remediation plans and permits as an excuse (see 4.4-14). However, the California courts have firmly established that an environmental analysis must be conducted at the earliest possible time when environmental effects caused by future expansion is a reasonably foreseeable consequence of the initial project. Mount Sutro Defense Committee v. Regents of the University of California, 77 Cal. App. 3d 20, 34, 143 Cal. Rptr. 365 (1st Dist., 1978).

Here, the report admits that this project could advance the cleanup of potentially contaminated soils, effecting surface water quality. However, the report fails to analyze this effect even though the cleanup could be rushed by the sale of the power plants. Moreover, the report admits that no permits have yet been issued. Therefore, no environmental analysis has been made. For the report to decline analysis at this stage is contrary to CEQA protocol.
[End U38]

[Begin U39]

This DEIR similarly declines to address environmental impacts with regard to water flow, thermal limits, and effluent constituent limits. It assumes that since RWQCB issued permits for these effects that the impacts have already been addressed. The report then shirks its duty by claiming that the RWQCB has the job of making sure there are no violations (see 4.4-15 & 16). This conclusion is a distortion of CEQA.

Sections 15253 and 21080.5 of CEQA allows the substitution of a qualified permit for a CEQA analysis as long as the permit addressed identical environmental concerns and that the project for which the permit was issued is the same project the current DEIR is analyzing. The situation here fails to meet both requirements.

First, the permit doubtfully could have conceived of the sale of the power plants when it was issued, as it does not contain mass limits, only concentration limits. Even if it did, the DEIR offers no indication.

Second, this divestiture project is different than PG&E's original project to operate. The current project involves selling the plant to an owner who will then be allowed to operate in an open market. When PG&E was given the initial permit, it could not operate on an open market. Therefore, the reliance on the existing permit for a finding of no significant impact is improper.
[End U39]

[Begin U40]

Additionally, the DEIR fails to consider the effects of a permit violation (i.e.: an adverse environmental impact) shouldering that responsibility onto RWQCB.

The purpose of CEQA is to *prevent* and *mitigate* possible adverse environmental impacts. This report fails to prevent possible impacts by allowing probable damage to occur (through a permit violation) and then relying on another agency to take action after the damage is done. Again, this flies in the face of what CEQA is designed to do.
[End U40]

XII. CONCLUSION

[Begin U41]
If the DEIR is properly revised, it should find that there are significant air quality impacts. This is not a devastating problem for this project. All it means is that air quality mitigations must be put in place, measures that likely will eventually happen for all of these plants anyway as they must meet increasingly more stringent air pollution requirements. It merely requires that they be employed now to avoid the deaths and suffering delay will cause for Bay Area residents.
[End U41]

[Begin U42]
For example, Potrero, is likely to be repowered (see DEIR at C-36), so requiring BACT before operations can be increased provides no additional burden on the new owner, other than accelerating the process. Offsets for any increases in PM should be minimal if BACT is employed. Thus, a tortured analysis trying to minimize emissions in a manner contrary to undisputed case law is unnecessary and a disservice to the project sponsor and the public.
[End U42]

If you have any questions regarding our comments, please feel free to call any of the undersigned. We may be reached by telephone at (415) 442-6647 and by E-mail at aramo@ggu.edu. Thank you for your consideration.

Sincerely,

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Alan Ramo, Attorney at Law, Director
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Note: Included with this comment were many pages of Exhibits A, B and C documents. Since these cannot be reasonably duplicated here on this web page they are not available electronically. Should the viewer require a copy of these, please contact Webmaster for a printed copy.

U. SOUTHEAST ALLIANCE FOR ENVIRONMENTAL JUSTICE (as Represented by Golden Gate University Environmental Law and Justice Clinic)

U1 The DEIR identifies the project's potential inconsistency with the regional air quality plan as a significant effect, which belies the commenter's claim that the DEIR minimizes the impact of the project on regional air quality.

U2 As stated on page 4.5-61, the DEIR indicates that increases in emissions would be significant if they would result in significant increases in local criteria air pollutant concentrations, in significant increases in health risks in the vicinities of the plants, or in significant increases relative to emissions projections used in regional air quality plans. The first two types of impacts (criteria air pollutants and health risks) were evaluated using standard thresholds rather than any percentage-, or ratio-, type threshold. The third type of impact (comparison with plan projections) did use a one-percent test as an indication of emissions estimates that would be notably out-of-sync with those developed for the regional air quality plan. It should be noted that the comparison with power plant projections was the basis for a project-specific impact determination, not a cumulative impact determination. Using the one-percent test, the DEIR concludes that emissions increases would be a significant effect of the project. Ironically, the one-percent test or "ratio" method, to which the commenter objects, is the only significance criterion by which air quality impacts due to the project were found to be significant in the DEIR. It is noted also that, in developing the one-percent criterion, the EIR consultant conferred with staff at BAAQMD (the agency responsible for developing emissions projections used in the regional air quality plan), who agreed that this approach was both reasonable and appropriate in this context (Guy, 1998). Please also see response to Comment U13. For additional information regarding cumulative impacts on regional ozone and PM-10 emissions, see responses to Comments U14 and U16.

Reference:

Guy, Bill, Bay Area Air Quality Management District, telephone communication, July 29, 1998.

U3 The choice of the endpoints does not fail to account for any substantial changes in operations which may occur at these plants. As discussed in Chapter 3 and Attachment C, the difference in incentives and opportunities between PG&E and any new owners will diminish, particularly starting in 2002. At that date, PG&E can enter the direct access market, just as the new owners. In addition, PG&E must add increasingly stringent emission control measures at its plants in the Bay Area. As a result, total NO_x emissions will fall after 1999 in any case assuming a constant behavioral change (the only assumption possible in this type of analysis). Any increase in electricity demand is likely to be relatively small in the three-year period from 1999 to 2001, and, with the expected addition of substantial new generation resources in the next five years (see Section 5.2.2 (page 5-3), most of this increased demand will be met by other facilities.

The EIR does not ignore potential air quality effects in the years between 1999 and 2005. The air quality section includes an comparison of power plant emissions under the Baseline scenario (with continued PG&E ownership), and A-Max scenario (new ownership) with projected power plant emissions contained in the *'97 Clean Air Plan*. The years of analysis are 2000 and 2003, because these are the years for which emission estimates are provided in the *'97 Clean Air Plan*. These analyses are summarized in the DEIR in Table 4.5-35 (on page 4.5-78), in Table 4.5-36 (on page 4.5-79 and in Table 4.5-37 (on page 4.5-80). The DEIR determined that if the plants were operated at the A-Max levels, there would be a significant, unavoidable but temporary effect. The impact would be significant in the year 2000, but with the implementation of Mitigation Measure 4.5-5, it would be less than significant by the year 2003.

Finally, the EIR does not minimize 2005 cumulative impacts associated with new owners of the plants simply because it does not compare the new owners' operations with PG&E's projected 2005 operations if PG&E were to retain the plants. Indeed, the EIR employs a conservative approach by attributing any changes in plant operations between 1999 and 2005 to the project itself. In any event, the DEIR does analyze PG&E's projected operations in 2005 as Alternative 1, the No Project Alternative (beginning on page 6-9). Thus, the EIR does acknowledge continued differences between PG&E and new owners in 2005.

U4 The capacity factors modeled in the DEIR as reported in Table 3.1 represent an annualized capacity factor for each generating unit. Actual operations vary during the course of a year, based on the demand at any time and the operational characteristics of a unit. Therefore, it does not make sense to use the capacity factors as strict operational limits on the power plants because, under a given set of circumstances, a given plant may need to be operated temporarily at higher levels to meet the immediate energy demand. Nor is it true that absent such limits the DEIR has failed to properly analyze the adverse impacts of the project. As discussed in Chapter 3 of the DEIR, the Analytical Maximum scenario represents the highest capacities at which the plants realistically could operate, taking into account a variety of limiting factors. As noted in the DEIR (page 3-12, second complete paragraph), the Analytical Maximum scenario is extremely unlikely to reflect a true operating scenario. A number of unlikely assumptions were made in running the SERASYM™ model so that the Analytical Maximum scenario would represent worst-case operating levels for purposes of environmental analysis. For example, the scenario assumes that all three fossil-fueled power plants would have an unlimited supply of natural gas at a price 25 percent below the least expensive supply of gas assumed to be available to fuel California power plants. Given the very conservative nature of this assumption, if circumstances were to change, as suggested by the commenter, it is much more likely that the natural gas prices paid by the plant owners would be higher, not lower, than the prices modeled, which would tend to suppress rather than boost operating capacities. Regarding other inputs, such as transmission system capability and operating procedures, these factors are more likely to favor new plants, not the plants being divested. For example, if existing transmission constraints were removed, it would make it more likely that generation would be boosted at more efficient plants, not at the less efficient Bay Area plants. Please also see the responses to Comments F53 and F54.

Please note that, in addition to analyzing the annual capacity factor changes, the DEIR also assesses the adverse effects of maximum 1-hour, 8-hour, and 24-hour operations of the power plants at substantially higher operating levels than the annual capacity factors. The results of this analysis are summarized in the tables addressing air quality concentrations. The concentration estimates for the Potrero, Contra Costa, and Pittsburg Power Plants are presented in Tables 4.5-29 (page 4.5-63), 4.5-31 (page 4.5-66), and 4.5-32 (page 4.5-68), respectively.

U5 BAAQMD developed Regulation 9, Rule 11 as a means of implementing Best Available Retrofit Control Technology (BARCT) for the source category of utility boilers. It should be noted that the power plants proposed for divestiture are existing permitted sources, which are subject to BARCT, rather than Best Available Control Technology (BACT), which applies to new sources. Under BAAQMD Regulation 9, Rule 11, the steam boilers at the three fossil-fueled power plants to be divested are subject to increasingly stringent standards for NO_x. Mitigation Measure 4.5-5 requires either permit modifications or changes to Regulation 9, Rule 11, either of which would assure that these increasingly stringent standards will apply to PG&E or to new owners. (The DEIR lists modification of Regulation 9, Rule 11, or equivalent permit revisions, as Mitigation Measure 4.5-5.) Moreover, to meet these standards, PG&E or the new owners would likely have two main options: (1) install more effective NO_x reduction technology, or (2) decrease the use of one or more steam boilers.

Thus, by 2005 and with implementation of Mitigation Measure 4.5-5, NO_x emissions, even under the A-Max condition, would be substantially less than under existing conditions (see Table 4.5-26 on page 4.5-57 of the DEIR). Therefore, two of the types of mitigation called for by the commenter (more effective emissions control technology and reduced capacity factors) are precisely the types of options that PG&E or new owners have to meet the requirements of Regulation 9, Rule 11, so no further mitigation would be needed.

The commenter also cites offsets as a possible mitigation measure; however, offsets in the form of emissions credits are not generally considered CEQA mitigation since they are not contemporaneous emissions reductions. With regard to offsets, see also response to Comment U17.

U6 Air quality significance criterion #1, "violation of an ambient air quality standard or substantial contribution to a projected violation of an ambient air quality standard," is an appropriate criterion to use in evaluating both project-specific and cumulative impacts and was used to evaluate both types of impacts in the DEIR. DEIR Tables 4.5-29, 4.5-31, and 4.5-32 were formatted specifically to allow for easy comparison with the concentration standards associated with significance criterion #1. The distinction cited by the commenter between how cumulative effects are to be examined for purposes of an Initial Study versus how they are to be examined for an EIR does not reflect the current CEQA

Guidelines. Current CEQA Guidelines Section 15130 (a) extends the concept of "cumulatively considerable," which has been the guidance for Initial Studies, to the discussion of cumulative effects in an EIR. The EIR's analysis of cumulative impacts comports with CEQA requirements. Please see responses to Comments U14 and U16.

U7 The Prevention of Significant Deterioration (PSD) regulation is used by BAAQMD when conducting a new source review. The facilities in this project are not new sources that would be subject to PSD or that would require emissions offsets. Thus, the PSD regulation would not normally apply to these plants. However, in order to conservatively judge whether the project would substantially contribute to violations of air quality standards, the EIR embraced and fully applied the PSD regulation. The 24-hour concentration change of 5 micrograms per cubic meter and the annual average change of 1 microgram per cubic meter, that are stated in criterion #1, are not actually the ultimate PSD standards contained in the PSD regulation. They are concentration increases that are defined in the PSD regulation as threshold levels, below which there would be no substantial contributions to a projected air quality concentration change. Under the PSD regulation, if a new source would exceed these very low threshold levels, then further analysis is required and additional standards apply. However, as indicated in Section 4.5 of the DEIR, the project emissions would fall below even these threshold levels. Therefore, the project's impact is less than significant.

U8 The DEIR does not imply that there would be no health effects for levels below those identified in the referenced studies. Instead, it uses the levels of 20 micrograms per cubic meter and 10 micrograms per cubic meter to determine if the total plants (existing emissions plus emissions from divestiture) are major causes of respiratory problems at the maximum receptor, similar to the methods used by EPA when establishing new PM-2.5 standards (see responses to Comments F62 and F74). When considering the impacts from divestiture alone, the increases in concentrations of the 1999 A-Max and 2005 A-Max concentrations over the Baseline concentrations were compared to the more stringent thresholds of 5 micrograms per cubic meter and 1 microgram per cubic meter.

U9 Although the study cited in the comment suggests a relationship between low levels of PM-10 and health effects, there is considerable uncertainty in the magnitudes of the health effects and relative risks at lower levels, as was stated in the EPA 1996 staff assessment report on PM-10 and PM-2.5 (see response to Comment F74). The data contained in the study that are cited in the comment show a higher relative risk for the San Francisco area than for other cities. However, a plot in the study shows a much higher error bound for the San Francisco data than for the other cities. The error bound for San Francisco extends to levels that are equivalent to or lower than other cities in the study. Thus, it cannot be concluded that the relative risks for San Francisco are actually higher.

All of the relative risks included in the plot were for the same exposure level of 100 micrograms per cubic meter, well above the maximum PM-10 level (57 micrograms per cubic meter) that was measured for the San Francisco area in the past three years. The maximum 24-hour average concentration reported for San Francisco in the cited study was 139 micrograms per cubic meter, occurring between 1981 and 1990, which again is well above the maximum level of recent years. Because of major changes in the types of fuels used in the PG&E boilers and because of the elimination of lead in gasoline in the mid-1980s, PM-10 concentration levels in the area have decreased significantly. Therefore, some of the conclusions in the cited study may not apply to present and future conditions.

U10 Conclusions cannot be drawn from the Thurston study (summarized in documents attached by the commenter) that there is increased vulnerability in the Bayview-Hunters Point area over other metropolitan areas. The relative risk coefficients described in response to Comment U9 show error bounds for the San Francisco data that are much greater than the other cities. Therefore, there is much greater uncertainty in describing the effects of a 100 microgram per cubic meter change (the normalized exposure level) for San Francisco than for other cities. Also, the study was carried out for the period from 1981-1990 when PM-10 levels were much higher than present-day levels in San Francisco. The highest 24-hour average level in San Francisco that was used in the study was 139 micrograms per cubic meter, which is much higher than the maximum level monitored in the last three years in the vicinity of the Potrero facility (57 micrograms per cubic meter). PM-10 ambient air concentrations in the Bay Area in the last few years have decreased for several reasons, including the elimination of leaded gasoline in automobiles, which were sources of fine particulate matter in the form of lead oxide, and the ceasing of fuel oil burning, which also is a source of particulate matter. Much of the particulate matter that was released into the atmosphere in the region in the 1980s contained toxic substances, such as lead from auto exhaust and polynuclear aromatic hydrocarbons from burning residual fuel oil in steam boilers. The PM-10 monitoring data at the Arkansas station in the Bayview Hunters Point area shows maximum ambient air levels that are lower than levels in other parts of the Bay Area (see Tables 4.5-29, 4.5-31 and 4.5-32).

The studies regarding higher incidences of respiratory related illnesses in the Bayview Hunters Point area that are cited on page 4.5-31 of the DEIR do not identify the causes of the respiratory related illnesses, nor do they relate hospitalizations to elevated exposure levels of particulate matter. On that page, the DEIR states that a detailed study would be necessary to better determine the cause(s) of the health effects. Such a study is beyond the scope of this EIR. In addition, there is no inference in the earlier study that the power plants are a major factor in the respiratory illnesses in the Bayview Hunters Point area, and the contributions of the power plants to existing and future local concentrations of criteria air pollutants in the area are minimal (see DEIR, Table 4.5-29, page 4.5-63).

Volume III of the EPA Air Quality Criteria Document for Particulate Matter (USEPA, 1996a) indicates that a number of factors and confounding parameters besides ambient air PM-10 levels can considerably affect respiratory related health effects, such as particle size and the composition of the particulate matter. With regard to the composition of particulate matter from natural gas combustion at the PG&E plants, there is very little information on the health effects from exposure to these substances. In other words, not all particulate matter is the same with regard to health effects. It is very important to include both composition and particle size when assessing health effects. Because this information was not available, the DEIR conservatively assumed that all particulate matter was the same with regard to health effects.

There is very little information on the composition of particulate matter emissions from gas-fired boilers, such as those used at the PG&E plants, mainly because the emissions of total particulate matter are so low that the levels of any toxic substances that may be contained in particulate matter are usually below the detection limits. Particulate matter from the combustion of fossil fuel, including natural gas, residual fuel oil and distillate fuel, consists of a carbon core with other substances adsorbed to the surface of the carbon core. The combustion of residual fuel oil and distillate fuel produces other products of incomplete combustion that are absorbed onto the carbon core. These products of incomplete combustion consist mainly of multi-chain carbon organic fragments, such as polycyclic aromatic hydrocarbons (PAHs). PAHs are a group of compounds that have been considered by USEPA and by the California Office of Environmental Health and Hazard Assessment (OEHHA) to be carcinogens. For oil, wood, and coal combustion, PAHs are considered to be one of the major toxic substances of concern. Particulate matter emissions from fossil fuel combustion may also include toxic metals that are both carcinogens and non-carcinogens. Most of these toxic metals are contained in the fuel initially.

With respect to natural gas combustion, there is little opportunity to form long-chain PAHs, because the starting fuel consists mainly of methane, which contains only one carbon atom per molecule. Therefore, the particles emitted from natural gas combustion contain mostly carbon. To verify this assumption, the measurement results for natural gas combustion were compared with measured emissions from the combustion of residual fuel oil. The comparisons are summarized in Table U10-1.

The emissions reported in the table are based on measurements for oil-fired and gas-fired electric utility steam boilers, which are reported in the updated EPA publication AP-42 (Version 5 sections 1.3 & 1.4 USEPA, 1998). Emission factors for the two fuels were converted to the common units (pounds of pollutant per million BTU of fuel combusted). For natural gas combustion, measurements were carried out for a number of PAHs but the levels were below the detection limits of the instrumentation. Although it is unclear whether these substances are actually present in the particulate matter, these substances were included in the analysis at one half the detection limit.

Using the conservative approach of including PAHs at one half the detection limit for natural gas combustion, Table U10-1. shows that total PAHs are about 5.7 percent of the levels measured for residual fuel oil combustion.

A similar comparison was conducted for the emissions of toxic metals from the combustion of the two fuels. The results in Table U10-1 show that total toxic metal emissions from combustion of natural gas were approximately 1.1 percent of the total toxic metal emissions from the combustion of residual fuel oil. These results show that the toxic component of particulate matter is significantly lower than particulate matter from residual fuel oil combustion. Table U10-1 also shows that total particulate matter emission from gas fired boilers are about 20 percent of the levels reported for oil fired boilers, for the same heat input.

Another important factor in the health effects from inhaling particulate matter relates to the deposition rates in the respiratory tract. A principal factor in affecting deposition rates is the particle size. Studies reported in the EPA Criteria Document for Particulate Matter (USEPA 1996) and in other literature (Raabe, 1984) show that deposition rates in the respiratory tract are higher in the size range between 1.0 micron and 2.5 microns and for particles less than 0.2 microns. Relative deposition rates for the size range between 0.2 microns and 1.0 micron are lower (see also response to Comment F74).

The cumulative particle size distribution for utility boilers firing residual oil indicates that 71 percent of the particles are less than 10 microns, 52 percent are less than 2.5 microns, 39 percent are less than 1 micron, and 20 percent are less than 0.625 microns. Since a considerable portion of the emissions are less than 2.5 microns, they can deposit in the respiratory tract.

Particulate matter emissions for natural gas combustion are usually less than 1 micron in size, with a considerable portion being between 0.1 microns and 1.0 micron (USEPA, 1998). Since a greater fraction of particles emitted from natural gas combustion appear to be in this size range, with lower deposition than emissions from fuel oil combustion, it can be inferred that a greater fraction from gas-fired emissions would be expired upon exhalation and would not be deposited in the respiratory tract. In the fine particle size range less than 0.1 micron, deposition in the respiratory tract particles would again increase.

References:

USEPA, Air Quality Criteria Document for Particulate Matter, Vol.III, EPA/600/P-95/001cF, April 1996.

USEPA, Compilation of Air Pollution Emission Factors, Version V, Sections 1.3 and 1.4, 1998.

Raabe, O., *Deposition and Clearance of Inhaled Particles*, Chapter 1. of *Occupational Lung Disease*, J.B. Gee, W.K. Morgan, and S.M. Brooks, editors, Raven Press, 1984.

U11 The comment attempts to relate annual emissions changes for the three PG&E fossil-fueled plants under the 1999 and 2005 A-Max scenarios directly to expected health effects, without addressing the actual ambient air concentration changes. It is concentration changes in the ambient air that are related to health effects. The DEIR shows on Tables 4.5-29 through 4.5-32 that the estimated maximum 24-hour average increases in

TABLE U10-1
COMPARISON OF MEASURED TOXIC PARTICULATE MATTER FROM THE COMBUSTION OF NATURAL GAS AND RESIDUAL (#6) FUEL OIL

ORGANIC COMPOUNDS	Natural Gas (lb/mmcfb)	Natural Gas (lb/mmbtu)	#6 Fuel Oil (lb/tgb)	#6 Fuel Oil (lb/mmbtu)	Ratio of NG/ Fuel Oil
Acenapthene*	9.00E-07[a]	8.82E-10	2.11E-05	1.40E-07	0.006
Acenaphthylene*	9.00E-07[a]	8.82E-10	2.53E-07	1.68E-09	0.527
Anthracene	1.20E-06[a]	1.18E-09	1.22E-06	8.08E-09	0.146
Benzanthracene	9.00E-07[a]	8.82E-10	4.01E-06	2.66E-08	0.033
Benzo(a)pyrene[b]	6.00E-07[a]	5.88E-10	--------	5.88E-10	1.000
Benzo(b)fluoranthene	9.00E-07[a]	8.82E-10	7.40E-07	4.90E-09	0.180
Benzo(g,h,i)perylene	6.00E-07[a]	5.88E-10	2.26E-06	1.50E-08	0.039
Benzo(k)fluoranthene	9.00E-07[a]	8.82E-10	7.40E-07	4.90E-09	0.180
Chrysene	9.00E-07[a]	8.82E-10	2.38E-06	1.58E-08	0.056
Dibenzo(a,h)anthracene	6.00E-07[a]	5.88E-10	1.67E-06	1.11E-08	0.053
Fluoranthen	1.50E-06[a]	1.47E-09	4.84E-06	3.21E-08	0.046
Indeno(1,2,3-cd)pyrene	9.00E-07[a]	8.82E-10	2.14E-06	1.42E-08	0.062
Phenanathrene	8.50E-06[a]	8.33E-09	1.05E-05	6.95E-08	0.120
Pyrene	2.50E-06[a]	2.45E-09	4.25E-06	2.81E-08	0.087
Total PAHs	**--------**	**2.14E-08**	**--------**	**3.72E-07**	**0.057**
METALS					
Antimony	--------	--------	5.25E-03	3.48E-05	--------
Arsenic	2.00E-04	1.96E-07	1.32E-03	8.74E-06	0.022
Barium	4.40E-03	4.31E-06	2.57E-03	1.70E-05	0.253
Beryllium	6.00E-06[a]	5.88E-09	2.78E-05	1.84E-07	0.032
Cadmium	1.10E-03	1.08E-06	3.98E-04	2.64E-06	0.409
Chloride	--------	--------	3.47E-01	2.30E-03	--------
Chromium	1.40E-03	1.37E-06	8.45E-04	5.60E-06	0.245
Chromium VI	--------	--------	2.48E-04	1.64E-06	--------
Cobalt	8.40E-05	8.24E-08	6.02E-03	3.99E-05	0.002
Copper	8.50E-04	8.33E-07	1.76E-03	1.17E-05	0.071
Lead	--------	--------	3.73E-02	2.47E-04	--------
Manganese	--------	--------	1.51E-03	1.00E-05	--------
Manganese	3.80E-04	3.73E-07	3.00E-03	1.99E-05	0.019
Molybdenum	1.10E-03	1.08E-06	7.87E-04	5.21E-06	0.207
Nickel	2.10E-03	2.06E-06	8.45E-02	5.60E-04	0.004
Phosphorous	--------	--------	9.46E-03	6.26E-05	--------
Selenium	1.20E-05[a]	1.18E-08	6.83E-04	4.52E-06	0.003
Vanadium	2.30E-03	2.25E-06	3.18E-02	2.11E-04	0.011
Zinc	2.90E-02	2.84E-05	2.91E-02	1.93E-04	0.148
Total Metals:	**--------**	**4.21E-05**	**--------**	**3.73E-03**	**0.011**
PARTICULATE MATTER					
PM (Total)	7.6	7.45E-03	5.67[c]	3.76E-02	0.198

SOURCE: EPA's AP-42, Version 5, Sections 1.3 and 1.4.

[a] Emission factors for natural gas that were identified as being less than method detection thresholds were assumed as one-half of the detection threshold and are identified above with an asterick.

[b] AP-42 did not provide a #6 fuel oil emission factor for benzo(a)pyrene. Therefore, it was assumed to be the same as natural gas.

[c] The particulate matter emission factor for #6 fuel oil is based on a sulfur content of 0.28.

ambient air PM-10 concentrations from divestiture would range from 0.5 to 3.6 micrograms per cubic meter at the maximum receptor. These maximum short-term increases are for localized areas and are not representative of increases for the entire region around the plants. Typical maximum short-term concentration increases in the area for population exposure, based on the modeling, would be considerably lower (less than 1.0 microgram per cubic meter). Most of the studies relating health effects from increases in exposure to particulate matter observed health effects when there were concentration increases of 20 to 25 micrograms per cubic meter for PM-2.5 and increases of 50 micrograms per cubic meter for PM-10. Other, more recent studies have reported observed health effects for increases of 10 micrograms per cubic meter, although with much greater uncertainty. None of the studies reported observed health effects for small increases in PM-10 concentrations (i.e., increases less than about 5 micrograms per cubic meter).

The EPA Criteria Document for Particulate Matter, which is cited in the response to Comment F74, shows a wide range in relative risk coefficients for concentration increases of 10 micrograms per cubic meter, varying by a factor of five. For greater increases, such as 20 to 50 micrograms per cubic meter, the Criteria Document indicates that health effects were observed and that relative risk coefficients were more certain. There is no indication in the document that there would be any health effects for increases less than 1 microgram per cubic meter. In fact, the EPA Criteria Document on Particulate Matter does not rule out a threshold below which no health effects would occur.

The risks at low levels, as identified in Exhibit C of the comment, were derived by extrapolating the relative risk plots for higher concentration increases to no concentration increase (zero concentration increase), even though there is no evidence that there would be any health effects at extremely low levels, especially for moderate background levels of short-term concentrations (30 micrograms per cubic meter). The studies do not report observed health effects at these small increases with moderate background levels.

The analysis that is referenced as Exhibit C in the comment extrapolates the relative risk coefficients that were derived from increases of 10 micrograms per cubic meter, and estimates relative risks for extremely small increases in concentration of about 0.02 micrograms per cubic meter. These very small increases were then used in Exhibit C to estimate increased mortality in the Bay Area. However, there is no indication that increases in particulate matter concentrations of 0.02 micrograms per cubic meter would cause any health effects at all, especially mortality. It is stated in Exhibit C that

> "...the studies do not prove a causal relationship between PM-10 and mortality, only an association..."

In fact, the studies show an association for only moderate increases in concentrations (20 to 50 micrograms per cubic meter), but do not show any association for extremely small increases in concentrations (0.02 to 1.0 micrograms per cubic meter). Therefore, the estimates in mortality identified in Exhibit C have no scientific basis.

The comment then estimates mortality for the proposed project by scaling the annual emissions changes for all three fossil-fueled plants to emissions for the proposed plant in Exhibit C (the San Francisco Energy Facility). The comment does not relate exposure levels to health effects. The comment builds on unfounded risk estimates for extremely low concentration increases identified in Exhibit C to estimate correspondingly unrealistic risk estimates for the divestiture project. Based on the small increases in concentrations from the project, there is no indication that there would be any increase in mortality or morbidity in the region. The DEIR does not suggest that high mortality and morbidity levels identified in the comment are insignificant. Instead, the DEIR states that the small increases of PM-10 concentrations from the project (under the A-Max scenarios) pose less than significant health effects.

U12 The methods that were used to assess the project impacts where background levels have already exceeded the ambient air standards are consistent with the approaches used by BAAQMD, in which the more restrictive thresholds described in Significance Criterion #1 were used. For further explanation on how this significance criterion was used, see response to Comment F74. With regard to particulate matter emissions, BACT is already used at the PG&E plants, which involves using natural gas, the cleanest of all fossil fuels. With regard to ozone, the precursor nitrogen oxides will be controlled by 90 percent over 1997 emission levels by installing selective catalytic reduction (SCR), which is BACT for these units. Offsets would be required only if the residual impacts after using BACT are significant (measurable). Since the impacts from divestiture did not exceed these levels, offsets are not needed.

U13 Significance criterion #5, the one-percent test, attempts to distinguish important differences between emissions forecasts developed for a given project and forecasts used in the regional air quality plan. Criterion #5 was modeled after a significance criterion developed by BAAQMD and recommended in its former CEQA Guidelines document (BAAQMD, 1985). It is acknowledged that the current *BAAQMD CEQA Guidelines* document (April 1996) no longer includes the one-percent test as a significance criterion. However, the nature of this project, which involves the sale of an existing emissions source, is so different from that of a typical development project, such as a new subdivision or office park, that it is not unreasonable to include significance criteria in addition to (i.e., to supplement, but not replace) those recommended in the current *BAAQMD CEQA Guidelines*. Unlike most emissions sources, power plants are a separate line-item on the regional emissions inventories that are used in regional air quality plans, which provide the basis for the type of comparison provided in the DEIR. It is noted also that, in developing this criterion, the EIR preparers conferred with staff at BAAQMD, who agreed that this approach was both reasonable and appropriate in this context (Guy, Bill, Bay Area Air Quality Management District, telephone conversation, July 29, 1998). Please also see response to Comment U16.

U14 The commenter indicates that the cumulative air quality analysis in the DEIR used the judicially discredited "ratio" theory to determine that the project's emissions would not be significant because they would comprise less than one percent of the region's emissions. The commenter is incorrect as to the standards and methodology of the DEIR.

While the one-percent test helps to characterize the severity of an impact, it is acknowledged that it alone is not a sufficient basis for concluding that a cumulative effect would be less than significant. In this case, the conclusions drawn in the DEIR are supported on two bases. First, since the emissions sources that are the subject of this project are covered under Air District permits and since the emissions estimates (including both predicted emissions increases and decreases) would be consistent with those permits, the changes in power plant emissions (regardless of year or whether they are project-specific or cumulative) are presumed to be less than significant under CEQA Guidelines 15064(i) and the *BAAQMD CEQA Guidelines*. As explained on page 4.5-61 of the DEIR, while the emissions changes themselves were deemed less than significant on a regulatory basis, other types of impacts that flow from changes in emissions were subject to further evaluation, such as changes in local concentrations and health risks and consistency with regional emissions projections (see Impacts 4.5-2, 4.5-3, and 4-5-5, respectively). Second, the estimated power plant emissions of ozone precursors and PM-10 (and its precursors) would be less under cumulative 2005 and 2015 conditions than under 1999 Baseline conditions and, therefore, they do not contribute to the cumulative regional effect of increased emissions from Bay Area growth and development. The necessary text revisions are provided below.

The following text and table is hereby added after the first paragraph on page 4.5-59 of the DEIR:

Year 2005 Cumulative

Since regional ozone concentrations reflect both precursors, ROG and NO_x, regional cumulative impacts from changes in power plant emissions can be evaluated by determining the net change in emissions of both of these pollutants, added together, relative to the emissions that are expected under the 1999 Baseline case.
Table 4.5-26a shows the net change in ozone precursor emissions (i.e., ROG and NO_x) from Bay Area power plants under various cumulative scenarios relative to the 1999 Baseline case. The estimates assume that BAAQMD modifies its Regulation 9, Rule 11 to apply to new owners. These emissions changes would occur under air quality permits and would be consistent with all emission limitations and standards; therefore, they are not considered to be significant. In addition, however, as shown in Table 4.5-26a, the net change would be negative as the decrease in NO_x emissions would more than offset the increase in ROG emissions. As such, Bay Area power plants would not contribute to the cumulative effect of increased emissions of ozone precursors from new development in the Bay Area on regional ozone concentrations.

TABLE 4.5-26a
CUMULATIVE CHANGES IN EMISSIONS OF OZONE PRECURSORS BY BAY AREA POWER PLANTS, 2005 AND 2015

	Change in Power Plant Emissions (tons per year) Relative to 1999 Baseline [a]			
Pollutant	**2005 A-Max**	**2005 Variant 1**	**2005 Variant 2**	**2015 A-Max**
Reactive Organic Gases	322	293	286	369
Nitrogen Oxides	-2,552	-2,618	-3,115	-2,440
Total Ozone Precursors:	-2,230	-2,325	-2,829	-2,071

a The net change in emissions are based on emissions estimates shown in Table 4.5-26 (1999 Baseline and Cumulative 2005 A-Max), Table G-5 (variant #1), Table G-14 as revised pursuant to comments by Enron on the DEIR (variant #2), and page 4.5-59 (2015 A-Max) and assumes that BAAQMD modifies its Regulation 9, Rule 11 to apply to new owners. Variant 1 and variant 2 are described in Chapter 5, Cumulative Impacts.

SOURCE: Environmental Science Associates

PM-10 concentrations reflect both direct sources of PM-10 and secondary sources of PM-10. For instance, power plants are both direct sources of PM-10 (i.e., PM-10 emitted from the stack) and secondary sources of PM-10 via emissions of ROG, NO_x, and SO_x. ROG, NO_x, and SO_x are precursors to PM-10 through chemical reactions in the atmosphere that change these gases to particulate compounds, such as ammonium nitrate and ammonium sulfate. Secondary PM-10 constitutes a substantial fraction of PM-10 concentrations in California; in some parts of the Bay Area, secondary nitrates, sulfates and organics together account for 25 to 30 percent of the total PM-10 concentration (California Air Resources Board, 1987). A study of wintertime PM-10 concentrations in the Bay Area identified these major contributors: wood smoke (approximately 40 percent); auto exhaust, road dust, and ammonium nitrate (each between 15 and 20 percent); and ammonium sulfate and marine aerosol (each less than 5 percent) (BAAQMD, 1992).

Since, as described above, regional PM-10 concentrations reflect both direct sources of PM-10 as well as secondary sources of PM-10, ROG, NO_x, and SO_x, regional cumulative impacts from changes in power plant emissions can be evaluated by determining the net change in emissions of these four pollutants, added together, relative to the emissions that are expected under the 1999 Baseline case. However, since not all of the precursors convert to PM-10, adjustments must be made to the emissions estimates prior to their summation and evaluation. Table 4.5-26b shows the net change in PM-10 and PM-10 precursor emissions (i.e., ROG, NO_x, and SO_x)

from Bay Area fossil-fueled power plants under various cumulative scenarios relative to the 1999 Baseline case. Appropriate adjustments have been made to the precursors as explained in the table footnote. (The estimates assume that BAAQMD modifies its Regulation 9, Rule 11 to apply to new owners.)

The emissions changes shown in Table 4.5-26b would occur under air quality permits and would be consistent with all emission limitations and standards, therefore, they are not considered to be significant. However, in addition, as shown in Table 4.5-26b, the net change would be negative as the decrease in NO_x emissions would more than offset the increase in PM-10, ROG, and SO_x emissions. As such, Bay Area power plants would not contribute to the cumulative effect of increased emissions of PM-10 and PM-10 precursors from new development in the Bay Area on regional PM-10 concentrations.

TABLE 4.5-26b
CUMULATIVE CHANGES IN EMISSIONS OF PM-10 AND PM-10 PRECURSORS BY BAY AREA POWER PLANTS, 2005 AND 2015

		Change in Power Plant Emissions (tons per year) Relative to 1999 Baseline [a]			
Source	**Pollutant**	**2005 A-Max**	**2005 Variant 1**	**2005 Variant 2**	**2015 A-Max**
Direct	PM-10	297	254	306	340
Secondary	ROG	13	12	12	15
	NO_x	-426	-437	-520	-407
	SO_x	7	7	6	8
Total PM-10:		-109	-164	-196	-44

a The net changes in emissions are based on emissions estimates shown in Table 4.5-26 (1999 Baseline and Cumulative 2005 A-Max), Table G-5 (variant #1), Table G-14 as revised pursuant to comments by Enron on the DEIR (variant #2), and page 4.5-59 (2015 A-Max)) and assumes that BAAQMD modifies its Regulation 9, Rule 11 to apply to new owners. Emissions for ROG, NO_x, and SO_x were adjusted by factors of 0.04, 0.17, and 0.08, respectively, to account for differences in the extent to which these pollutants contribute to regional PM-10 concentrations. The NO_x adjustment factor was provided by comments by SAEJ (see comment letter U, Comment 22) on the DEIR. The adjustments for ROG and SO_x are rough approximations taking into account their relative contributions to the regional emissions inventory and their relative contributions to regional PM-10 concentrations. Variant 1 and variant 2 are described in Chapter 5, Cumulative Impacts.

SOURCE: Environmental Science Associates

The first full paragraph on page 4.5-59 of the DEIR is hereby revised as follows:

> The City and County of San Francisco uses 2015 as an analysis year for evaluating the long-term environmental impacts of cumulative development. Power plant emissions estimates have been made for 2015 based on the emissions estimates for 2005, as adjusted to reflect population growth projected for the Bay Area. In 2015, under the Analytical Maximum scenario and assuming that BAAQMD Regulation 9, Rule 11 would be modified, Bay Area power plants would emit approximately 6,803 tons per year of carbon monoxide, 790 tons per year of ROG, 1,870 tons per year of NO_X, and 722 ~~169~~ tons per year of PM-10. If BAAQMD Regulation 9, Rule 11 were inapplicable, NO_X emissions in 2015 would be approximately 7,872 tons. As a percentage of regional emissions in 2015, the change in power plant emissions over 1999 baseline conditions would be less than 1 percent for carbon monoxide, ROG, SO_X, and PM-10. For NO_X, the change would be 1.5 percent assuming applicability of Regulation 9, Rule 11 and +1.6 percent assuming inapplicability of that rule. ~~Therefore, with the modification of BAAQMD Regulation 9, Rule 11 as required by Mitigation Measure 4.5-5, this increase would be less than significant since no pollutant would increase by more than one percent of regional emissions~~. As shown in Tables 4.5-26a and 4.5-26b, the net change in Bay Area power plant emissions of ozone precursors and PM-10 (and its precursors) in 2015 would be a decrease compared to 1999 baseline conditions. Therefore, Bay Area power plant emissions would not contribute to the cumulative effect of increased emissions from new development in the Bay Area on regional ozone and PM-10 concentrations.

U15 As discussed in response to Comment U14, there would be a net decrease in emissions of PM-10 and PM-10 precursors (ROG, NO_x, and SO_x) from power plants in the Bay Area. Thus, to whatever extent power plant emissions of PM-10 contribute to regional health concerns under 1999 baseline conditions, that effect would be less under future cumulative conditions. With respect to Dr. Fairly's analysis supplied by the commenter, please see response to Comment U11.

U16 The commenter raises numerous issues, which are addressed individually below.

With respect to a regional PM-10 plan, it is acknowledged that no such plan has been developed to address the region's nonattainment designation with respect to the state PM-10 standard since none is required under the California Clean Air Act. The *'97 Clean Air Plan* states that, while the plan does not address PM-10 specifically, several of the control measures in the plan would reduce PM-10 concentrations (BAAQMD, 1997). Specifically, the *'97 Clean Air Plan* cites the control measures reducing vehicle-miles-traveled and NO_x emissions as sources of PM-10 reductions by reducing two substantial components of ambient PM-10 concentrations, i.e., road dust and nitrates, respectively.

With respect to the federally mandated air quality plan, the DEIR indicates on page 4.5-16 that a revised State Implementation Plan (SIP) will be required due to U.S. EPA's decision to change the designation of the Bay Area back to “nonattainment” for the national ozone standard.

With respect to the regional plan addressing the state ozone standard, it is acknowledged that this plan does not predict attainment of the state ozone standard at all places and at all time in the Bay Area for the foreseeable future. However, it does predict continued improvement in regional ozone concentrations. Emissions of both ozone precursors (ROG and NO_x) are expected to decrease between 1997 and 2003, and a reduction in the precursors would logically result in lower ozone concentrations. With implementation of the measures included in the *’97 Clean Air Plan*, basin-wide ROG emissions are expected to decline from 488 to 373 tons per summer day between 1997 and 2003, and basin-wide NO_x emissions are expected to decline from 632 to 480 tons per summer day over the same period (BAAQMD, 1997). Such emissions estimates as those prepared for the *’97 Clean Air Plan* take into account expected growth and development in the Bay Area.

With respect to the approach to cumulative air quality analysis, the commenter essentially advocates a significance threshold of “one additional molecule” of a nonattainment pollutant in a nonattainment area. Such an approach is not required or supported under the CEQA Guidelines. The CEQA Guidelines refer to a *substantial* contribution to existing or projected air quality violation as a basis for determining significant effect, not just *any* contribution. In addition, there is a distinction to be noted between existing conditions and project effects. The commenter cites a sentence from the setting section; however, the project-specific and cumulative analyses both focus on the net environmental change related to the project. Therefore, the question is not whether power plant emissions contribute “nonattainment” pollutants to the atmosphere, but whether power plant emissions would increase or decrease relative to a baseline value. For cumulative analysis, the 1999 baseline scenario represents the “baseline” value to which cumulative scenarios are compared in the EIR. This is the appropriate approach to cumulative impact analysis in an EIR. The response to comment U14 examines the regional cumulative emissions changes of the two pollutants for which the Bay Area is in “nonattainment,” ozone and PM-10, and concludes that the net changes in power plant emissions of ozone precursors and PM-10 (and its precursors) would be negative compared to the 1999 Baseline case and, as such, would not contribute to the cumulative effect. For local cumulative concentration effects, please see the column on the far right-hand side of DEIR Tables 4.5-29, 4.5-31, and 4.4-32.

U17 Though how much the divested plant will operate is uncertain, it is very improbable that the Potrero Power Plant would operate more than the level resulting from the operating assumptions associated with the Analytical Maximum case (see responses to Comments F53 and F54). Although the DEIR forecasts Analytical Maximum annual capacities for the Potrero plant to be 44 percent in 1999 and 40 percent in 2005, for these Analytical Maximum scenarios, Potrero Unit 3 (the steam generating unit) is forecast to operate at a 75.6 percent capacity factor in 1999 (see DEIR Table G-4) and at a 63.5 percent capacity factor in 2005 (see DEIR Table G-6). These are unprecedented levels of operation since a steam generating unit typically averages no higher than about a 50 percent capacity factor.

In preparing this Responses To Comments Document, the project team analyzed a minor change to the 1999 heat rate for Potrero Unit 3, a steam boiler. The resulting changes in forecasts from the SERASYM model are analyzed below in detail so that the commenter can see how changes in the capacity factors would affect air quality conclusions. In general, it would seem that only Impact 4.5-5 is sensitive to minor (or even moderate) changes in capacity factors. Impact 4.5-5 was identified as a significant, unavoidable, but temporary impact of the project (ending in 2003). With increases greater than those identified below, Impact 4.5-5 would still be significant in 2003. However, no other modifications are known that would cause any such increases, and the Analytical Maximum results are designed to capture maximum possible operations. The other three units at the Potrero plant are all distillate-fired combustion turbine (CT) peaking units that are limited by BAAQMD rules to operating no more than 10 percent of the year. They are used for reliability purposes by the ISO and it is inconceivable that they would be employed much more heavily than projected unless they were both converted to natural gas fuel to reduce variable costs of operations and they were exempted from BAAQMD operating time limits. Assuming either occurrence would be speculative. Thus, since the Analytical Maximum case represents an extremely high (and unlikely) level of operations for the plant, consideration of the emission levels resulting from still higher levels of operations is not warranted.

As described above, new information from PG&E's 1998 Title V submittal, which is part of the on-going air quality permitting process, indicates a change in the heat rate (a direct measure of unit efficiency) for Potrero Unit 3 at this unit's higher levels of generation. The 1999 Baseline and Analytical Maximum Scenarios have been rerun to reflect the updated Potrero heat rates. No other scenarios need updating, because the updated heat rates for Potrero Unit 3 were already included in the 2005 model runs in the DEIR. The modified results forecast that the overall annual capacity factor for the Potrero Power Plant under the 1999 Baseline Scenario (continued PG&E ownership) would be about 1.5 percent higher than reported in the DEIR, increasing from 24.6 to 26.1 percent. The 1999 Analytical Maximum scenario (with the revised heat rate) would increase 4.5 percent above the value reported in the DEIR, from 44.1 to 48.6 percent. These changes would raise the Baseline scenario for expected PG&E operations of the Potrero plant in 1999 and, although the changes would raise the Analytical Maximum capacity factors for the Potrero plant a slightly higher percentage, upon review, the consequences of these changes are minimal and as analyzed below, the changes do not affect the conclusions of the DEIR. Were these changes in operations to affect any topical area, the area of concern would be air quality. A brief summary of the effects of these changes on air quality (for 1999) are provided below. Because the 1999 Baseline would increase at the Potrero Power Plant, the incremental change between the 1999 Baseline and the 2005 Analytical Maximum would be slightly reduced in all cases, because, as stated above, the 2005 Analytical Maximum already includes the more efficient heat rate for Potrero Unit 3.

1) *Increased emissions of criteria pollutants in the air basin.* Impact 4.5-1 noted that potentially increased electricity generation at the divested power plants would result in increased emissions of criteria air pollutants. The DEIR concluded that this impact would not be significant because the "direct" sources associated with the emissions are covered, and would continue to be covered, by existing air permits. Since the emissions increases would be consistent with all emissions limitations and standards imposed by the air district that issues the permit, they would not be considered significant. The modified capacity factors would not affect the results of this analysis. Although the forecast annual emissions under both the 1999 Baseline and the 1999 Analytical Maximum scenarios would increase at the Potrero plant, the Potrero units would still be subject to the standards and operational limitations of the air permits, and these increases would therefore be less than significant. Whereas forecast annual emissions would be increased slightly by this modification (because the plant is more efficient in producing electricity), it should also be noted that the modification described actually means that the Potrero Power Plant would generate less pollutants per kWh than was previously assumed.

2) *Increased local concentrations of criteria air pollutants.* Impact 4.2-2 addressed local concentrations of criteria air pollutants. To assess the effect of the revised heat rates and resultant annual capacity factors on this impact analysis, the project contributions of the Potrero Power Plant to the criteria pollutant concentrations reported in the DEIR (Table 4.5-29, page 4.5-63) were increased by 3 percent (reflecting a 4.5 percent change in the 1999 Analytical Maximum less the 1.5 percent change in the 1999 Baseline). After increasing the effect of the Potrero Power Plant, the resultant concentrations were still well below the applicable state and federal standards, with the exception of 24-hour PM-10 concentrations. The estimated worst-case background concentration for San Francisco already exceeds the state PM-10 24-hour standard of 50 $\mu g/m^3$ by 7 $\mu g/m^3$. The revised difference between the Potrero plant contribution to the 1999 Baseline and the plant's contribution to the 1999 A-Max would be 0.52 $\mu g/m^3$ (rather than 0.5 $\mu g/m^3$, as presented in the DEIR) for the worst-case 24-hours, which would be well below the 5 $\mu g/m^3$ significance threshold. Therefore, there would be no change in the conclusion in the DEIR that this impact would be less than significant.

3) *Increased health risk from toxic air contaminants.* Impact 4.5-3 identified the increased combustion of fossil fuels associated with the project as having a less-than-significant effect on health hazards. The increased health risk from exposure to carcinogenic substances and the chronic and acute hazard indices for exposure to non-carcinogens would all be considerably below the relevant significance thresholds. To assess the effect of the modified annual capacity factor for the Potrero Power Plant, the emissions of toxic substances were increased by the change in capacity factors (1.5 percent for the 1999 Baseline and 4.5 percent for the 1999 Analytical Maximum). The resultant cancer risk from the emissions changes would be 0.18 in a million for the 1999 Baseline and 0.24 in a million for the 1999

Analytical Maximum scenarios, still well below the 10 in a million significance threshold. The chronic health hazard indices would be 0.021 and 0.032 for the 1999 Baseline and 1999 A-Max cases, respectively, and the acute health hazard indices would be 0.21 for both the baseline and A-Max cases. All of these values are well below the index threshold of 1.0. Therefore, even with the revised Potrero plant capacity factors, this impact would remain less than significant.

4) *Loss of FTP cleanup programs and resulting FTP nuisance effects.* Impact 4.5-4 indicated that transfer of ownership of the fossil-fueled power plants could affect FTP deposition and that the new owner of the Delta power plants could discontinue PG&E's existing FTP cleanup program. In the case of the Potrero Power Plant, PG&E does not maintain FTP programs there but addresses claims on an as-needed basis, and the predominant local winds carry most FTP from the plant out over San Francisco Bay. The DEIR therefore concluded that this impact would be less than significant. Given the minor changes in forecasted annual capacities, this impact would continue to be less than significant.

5) *Potential inconsistency with regional air quality plans.* Impact 4.5-5 stated that the project would potentially be inconsistent with the *'97 Clean Air Plan* for the San Francisco Bay Area, which would be a significant impact. The inconsistency was described both qualitatively and quantitatively. From the qualitative standpoint, the project would potentially be inconsistent with a specific control measure contained in the *'97 Clean Air Plan* if the BAAQMD declines to modify Regulation 9, Rule 11. (As noted in response to Comment F1, the District is committed to modifying the rule so that it will continue to apply to the fossil-fueled plants, regardless of ownership.) From a quantitative standpoint, emissions estimates from this EIR were compared to those contained in the *'97 Clean Air Plan*. Emissions estimates shown under Impact 4.5-1 were interpolated to correspond to the emissions projections included in the *'97 Clean Air Plan* for Years 2000 and 2003.

Assuming continued application of Regulation 9, Rule 11, NO_x emissions from the fossil-fueled plants under the Analytical Maximum scenario would exceed *'97 Clean Air Plan* regional projections by about 1.4 percent in Year 2000, which would be greater than the 1-percent significance threshold. By Year 2003, project NO_x emissions would be consistent with the *'97 Clean Air Plan* (i.e., the net difference in regional emissions would be less than 1 percent). Absent BAAQMD Regulation 9, Rule 11, projected NO_x A-Max emissions would exceed *Clean Air Plan* projections by about 2.5 percent in Year 2000 and by 3.4 percent in Year 2003.

Given the assurances of the BAAQMD (see response to Comment E1) and in light of Mitigation Measure 4.5-5, it is assumed for purposes of this discussion that BAAQMD will modify Regulation 9, Rule 11 to apply to the new power plant owners. Therefore, from a qualitative standpoint, the proposed project is expected to be consistent with the *'97 Clean Air Plan* as of 2003. However, as noted above, the modified heat rates and capacity factors for the Potrero Power Plant would result in slightly increased emissions from the Potrero plant. As shown in Table 4.5-37 of the DEIR (page 4.5-80), only NO_x emissions are close to the 1 percent significance standard. With the revised heat rate factors for Potrero, and assuming the continued application of BAAQMD Regulation 9, Rule 11, regionwide NO_x emissions would still be above the 1 percent significance standard in 2000 (significant) and below the 1 percent significance standard by 2003 (less than significant). Impact 4.5-5 would thus remain significant and unavoidable, though temporary.

U18 The Analytical Maximum Potrero Power Plant annual capacity factor would be 40 percent in 2005 (see Table 3.1 and Table G-6 in the DEIR). A model run from the 2005 Analytical Maximum was reviewed day by day, and the daily plant capacity factors ranged from 0 percent to 67 percent. The majority of the days had capacity factors between 30 and 60 percent. These daily levels were reviewed closely in the DEIR in the analysis of ambient air quality contaminant concentrations near the Potrero Power Plant (see Table 4.5-29 on page 4.5-63) and, as shown in the two right-hand columns of Table 4.5-29, the effect of the emissions from the project are minimal in comparison to all of the ambient air quality 1-hour and 24-hour standards.

U19 The basic modeling assumptions used to derive the capacity factors are set forth in the DEIR at pages 3-8 through 3-13. The commenter is specifically referred to the first paragraph of page 3-9 of the DEIR, which describes briefly the qualifications of SERA in running the model for more than a decade and also notes that an expanded list of modeling assumptions and discussion of the modeling is presented in Attachment G to the DEIR. Attachment G has 16 pages of text and 20 data tables that address model assumptions and results. This level of information is meant to enable the public and decisions-makers to make an independent, reasoned judgement.

For further clarification, an assumption used in deriving the capacity factors that was not fully discussed in Chapter 3 or Attachment G of the DEIR is that a generating unit's maximum net capacity value may vary during the course of a year, particularly for a combustion turbine because its output capability is affected by the surrounding ambient air temperature. In such instances, the DEIR analysis used an average capacity value in the annual capacity factor calculation. Such seasonal capacity variations are present at Hunters Point 1, Potrero 4, Potrero 5, and Potrero 6 combustion turbine units, which have the following monthly varying ratings:

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
MW	56	55	54	53	50	48	49	49	48	49	54	56

The rating of each steam boiler generating unit is invariant during the course of a year and those of the units being offered for divestiture are presented in the tables found in Attachment G to the DEIR.

U20 The cited value of 44 percent relates to the estimated annual capacity factor for the Potrero Power Plant in 1999 under Analytical Maximum operating assumptions. Given the conservative assumptions underlying the Analytical Maximum scenario, it is not foreseeable that the plant would operate at an annual capacity factor higher than that identified under the Analytical Maximum (see responses to Comments F53 and F54), and since DEIR Table 4.5-29 shows that annual-average concentrations in the vicinity of the Potrero power plant would not exceed the corresponding ambient standards (even under Analytical Maximum conditions), there is no basis upon which to impose a plant-specific annual cap on generation. In contrast to the annual-average concentrations, which reflect the 44 percent capacity factor cited above, the DEIR analysis of concentrations for averaging periods of 24-hours and less reflects maximum daily emissions rates from the Potrero units. Thus, the potential adverse impacts on both annual averages and lesser averaging periods have been fully evaluated in the DEIR.

U21 The BAAQMD's Arkansas Street station data is presented since it is the closest monitoring station to the Potrero Power Plant. There is no monitoring station in the immediate vicinity of the plant. The analytical approach for impact assessment assumed that the data from the monitoring station on Arkansas Street was entirely unaffected by the plant, but is representative of background conditions (i.e., not including a power plant increment) in the project vicinity. Use of monitoring data from the closest station as the basis for background concentrations is the conventional approach in developing concentration estimates from a facility (transportation, industrial, etc.) that can be compared with ambient air quality standards. Worst-case incremental concentrations from the power plant (shown in Table 4.5-29 of the DEIR) were added to background concentrations that were derived from data collected at the Arkansas Street station. This is a conservative approach since it is possible that the measurements at that Arkansas Street station include some incremental contribution from the Potrero Power Plant, and if so, then the DEIR double-counts that increment by assuming no such contribution.

U22 It is true that a portion of NO_x emissions will eventually convert to secondary nitrate particulate matter (secondary aerosols), although reaction times can vary considerably. Conversion rates can range from less than 1 percent per hour (Randerson, 1984) to as high as 10 to 30 percent per hour (California Air Resources Board, 1998). However, a recent study indicated that in power plant plumes, nitrate particulate matter does not begin to form until at least 20 to 40 minutes after nitrogen oxides are released to the atmosphere (Seigneur, 1998). For typical wind speeds in the area, conversion to nitrate would not begin until the plume travels three to six miles from the emission source. The study (Seigneur, 1998) indicates that maximum conversion would occur after an early morning release (7:00 a.m.) of nitrogen oxides on a day with relatively high ozone levels in the atmosphere. For emission releases occurring at 5:00 p.m., nitrate aerosols would not begin to form until about five hours of travel time. A key factor in the conversion of nitrogen oxides to nitrate aerosol involves a series of complex reactions in which atmospheric ozone reacts with nitrogen dioxide (NO_2) to form the nitrate (NO_3) radical. However, the high initial concentration of nitric oxide (NO) in the power plat plume tends to scavenge atmospheric ozone, limiting the availability of atmospheric ozone to be available to react with nitrogen dioxide, an important step in forming nitrate aerosol.

Since the receptors with the maximum contributions of particulate matter are near the power plants (approximately one mile away), there is very little opportunity for nitrate aerosol to form in that short time period and nitrate would not contribute to particulate matter levels at the maximum receptors. With regard to larger distances from the plant, a portion of the nitrogen oxides emissions would eventually convert to nitrate particulate matter. However, there will be less secondary aerosol formed from the plant emissions in the future because of large reductions in NO_x emissions to meet BAAQMD Regulation 9, Rule 11. Thus, there will be reduced nitrate aerosol contributions to regional particulate matter levels. Please refer to response to Comment U14.

References:

California Air Resources Board, telephone communication, November 1998.

Randerson, D., *Power Production and the Atmosphere*, Chapter 1 of Atmospheric Science and Power Production, DOE/TIC – 27601, U.S. Department of Energy, 1984.

Seigneur, C., P. Karamchandani, and A. Koo, *Reduced Gas-Phase Kinetic Mechanism for Atmospheric Plume Chemistry*, ES&T, Vol. 32, No. 11, 1998

U23 Atmospheric dispersion modeling conducted for this DEIR and, subsequently, in response to Comment B6 was limited in scope, and was performed only to refine the air quality impact analysis and supplement the health risk assessment (HRA). As discussed on page 4.5-42 of the DEIR, the HRA for air quality was initially based on work performed by PG&E in 1992. Modeling data and analysis from these PG&E 1992 HRA studies for the Potrero, Contra Costa, and Pittsburg Power Plants were utilized to evaluate impacts of the divestiture project. The DEIR analysis was accomplished by updating air pollutant emission information from the 1992 PG&E studies for the three divestiture project analysis scenarios (1999 baseline, 1999 A-Max, and 2005 A-Max).

The 1992 PG&E HRA studies were of varying detail. The Potrero HRA study provided very detailed information on sources, impacts, and locations of impacts. The PG&E HRA studies for the Pittsburg and Contra Costa Power Plants, while detailed, were based on "screening" level analyses which were imprecise on locations of plant impacts, and were conservative in nature. During the analysis of these data, the conservative nature of the Pittsburg Power Plant's 1992 HRA screening data appeared in need of refinement for this DEIR. Similarly, air quality issues with the Potrero and Hunters Point Power Plants (Hunters Point Power Plant was initially part of the DEIR analysis but was later removed from A.98-01-008 in July 1998) indicated that further refinement of the 1992 PG&E studies were needed. Conversely, analysis of the Contra Costa Power Plant for the DEIR indicated that, although the PG&E 1992 HRA study data provided conservative results, local impacts were sufficiently less than significant to not require further refinement for the purposes of this DEIR.

PG&E provided model input source parameter data for the Pittsburg and Potrero Power Plants, meteorological data from PG&E-operated monitoring stations at both plants, and grids of receptors networks suitable for use at each plant. (Receptors are points where an atmospheric dispersion model predicts impacts from pollution sources being simulated by the model.) Included in these receptor grids were the locations of sensitive receptors close to both the Pittsburg and Potrero Power Plants, as identified by PG&E. The receptor network for the Pittsburg Power Plant is an area representing the City of Pittsburg. For the Potrero plant, the receptor network covered sensitive receptors in the immediate vicinity west of the Potrero plant and south to a distance of about 3.5 km (2 miles) covering the northern elevated portion of the Hunters Point/Bayview area. Both of these analyses considered the local topography. The Pittsburg plant analysis was performed with meteorological data for 1994, while the Potrero plant analysis utilized data for the period 9/28/91 to 9/28/92.

The dispersion model analysis was conducted using the Industrial Source Complex Short Term 3 Model (ISC3), Version 97363. This model was developed and approved for use by the U.S. Environmental Protection Agency and represents the state of the art in atmospheric dispersion modeling. The model was used assuming standard regulatory default options and BAAQMD modeling guidelines.

Air pollutant emissions used in the analysis presented in the DEIR were derived from data presented in Section 4.5 of the DEIR, as well as data presented in Attachment G. Short-term (24-hour average) PM-10 emissions for the Pittsburg Power Plant analysis were derived from a special simulation model analysis discussed in Section 3.2 of Attachment G.

Related information to this modeling discussion in contained in response to Comment 1-9.

U24 Atmospheric dispersion modeling has been routinely utilized since the 1970s as an analysis tool to evaluate the local fate and transport of air pollutants. A suite of mathematical models have been developed and refined by the U.S. EPA and others for use by analysts and regulators. Lists of these EPA approved models and methods of application of the models are provided at 40 Code of Federal Regulations Part 51, Appendix W. Many carefully conducted model prediction versus ambient monitoring data studies have been conducted over the years. To summarize these studies is well beyond the scope of this EIR, however, in general, it can be said that when the appropriate EPA approved model is properly utilized, the model-predicted impacts can be expected to be at least within a factor of 2 of actual field measurements or better (40CFR51, Appendix W). This factor of 2 is accepted by the EPA as a reasonable measure of model performance. Thus, from the perspective of regulators, the atmospheric dispersions models recommended for use by the EPA do and have been shown to "predict present effects from present pollution source conditions," within an accepted level of accuracy.

The following new reference is hereby added to Section 4.5:

Federal Register, July 1, 1997.

U25 With respect to model assumptions, please see response to Comment U24. Naturally, any changes in input data will affect the results of the model. Since the conservative Analytical Maximum capacity factors were used as input model data for the EIR, there is no need to further demonstrate how changes in such input data would affect the outcome.

U26 Ozone is normally characterized as a regional pollutant and is, therefore, appropriately the subject of a regional air quality planning effort. The DEIR addresses the project impact in the context of this regional air quality planning effort beginning on page 4.5-77 under Impact 4.5-5. The discussion of cumulative power plant emissions of ozone precursors has been revised. Please see the response to Comment U14.

U27 The DEIR does not dismiss the significance of the project's ozone precursor emissions. Page 4.5-18 of the DEIR shows a table in the text of NO_x emissions limits, per million Btu of energy consumption, that are allowed for PG&E's boilers between 1997 and 2005. The table shows that NO_x emissions for the intermediate year of 1999 will decrease by about 39 percent per million Btu of energy consumption compared to 1997 levels. It is these reductions on a per million BTU basis that will reduce precursor effects on ozone formation. Since, on a given day, the maximum operating rates under the 1999 A-Max scenario are not expected to change from the 1999 Baseline, the daily NO_x emissions will not change from the 1999 Baseline emissions, even though total annual emissions can be higher under divestiture for 1999.

In 2005, short-term and annual emissions will be reduced considerably compared to the 1999 Baseline. While it is possible that emissions from the plants would be less in 2005 under PG&E's continued ownership than with divestiture (and they may not, depending on how PG&E chose to operate the plants at that time), the environmental impacts of the project are properly judged in comparison with the baseline, the existing physical setting in 1999. Furthermore, the analysis of Alternative 1, the No Project Alternative (beginning on page 6-9 of the DEIR), indicates how the environmental impacts of the project in 2005 would differ from PG&E's continued ownership of the plants. See also Table G-2 of the DEIR for 2005 emissions data for Alternative 1, which can be compared to Table G-6 concerning 2005 emissions data for the project.

U28 The significance threshold is based on emissions inventories and forecasts developed for the *'97 Clean Air Plan* ('97 CAP), which is the state-mandated air quality plan, not the SIP, which the federally mandated air quality plan. The state standard, nonattainment of which is the trigger for the '97 CAP, is more stringent than the corresponding national standard, nonattainment of which is the trigger for the SIP. Because of this, the '97 CAP invariably includes more control measures than the SIP. For instance, Regulation 9, Rule 11 is a control measure identified in the '97 CAP that has not been incorporated into the

SIP. The DEIR recognizes the seriousness of the potential increase in emissions under the project relative to those assumed for the '97 CAP and identifies that effect as significant.

U29 As discussed in response to Comment U14, by 2005, power plant emissions of ozone precursors and PM-10 (and its precursors) would be less than under 1999 Baseline conditions. Therefore, power plant emissions would not contribute to the cumulative effect of increased emissions from additional growth and development in the Bay Area. However, prior to 2003, the DEIR predicts that Bay Area power plant emissions would be significantly greater than those foreseen in the *'97 Clean Air Plan*. The essence of this project-specific impact is that power plant emissions may well increase relative to 1999 Baseline conditions, at least during the first couple of years after divestiture (1999 and 2000), when the *'97 Clean Air Plan* anticipated a decrease, and may not decrease at the rate assumed in the *'97 Clean Air Plan* after that time. The latter effect, i.e., decreases that do not match the rate that is anticipated, is referred to by the commenter as "minimization of reduction." (The DEIR describes this effect beginning with the last paragraph on page 4.5-80.) The commenter's conclusion that such effects would be significant is consistent with the DEIR, which also concludes that the effect would be significant, at least through 2002. The one main difference is that the commenter characterizes the effect as "cumulative," while the DEIR identifies it as a project effect. Please see response to comment U16 for information concerning the regional air quality plans and their connection to future trends in ozone and PM-10 levels. Please also see response to Comment U27 concerning comparison of PG&E's continued ownership beyond 1999 to the proposed sale of the plants.

U30 The DEIR notes on page 4.5-16, second full paragraph, the recent decision by U.S. EPA to re-designate the Bay Area back to "nonattainment" for the national one-hour average ozone standard, which triggers the need for a revised SIP. The revised SIP must be adopted by the Association of Bay Area Governments, BAAQMD, and the Metropolitan Transportation Commission and submitted to U.S. EPA, through the California Air Resources Board, by June 15, 1999. The DEIR identifies the increase in power plant NO_x emissions as a significant, unavoidable impact of the project (see Impact 4.5-5 on page 4.5-77 of the DEIR). The discussion of cumulative power plant emissions of ozone precursors has been revised; please see the response to Comment U14. Also, please refer to the discussion of the distinction and application of Best Available Retrofit Control Technology (BARCT) (existing sources) and Best Available Control Technology (BACT) (new sources) in response to Comment U5.

U31 This apparent inconsistency can be explained through reference to the different averaging periods of the various ambient air quality standards. To calculate worst-case concentrations of carbon monoxide, nitrogen dioxide, and sulfur dioxide for averaging periods from one-hour to 24-hours, the maximum hourly emissions rates from Potrero Power Plant sources were used in combination with actual meteorological data compiled at the plant. This essentially assumes that on a maximum day the power plant would operate at full capacity for periods including 24-hours, and since the maximum emissions rate at full capacity would be the same under all scenarios in a given year (such as 1999 Baseline and 1999 A-Max), then it follows that the corresponding maximum concentrations would also be the same. It should be noted that Table 4.5-29 indicates that maximum concentrations of these pollutants for these averaging periods (i.e., including the power plant increment and the background increment) would be less than the corresponding ambient air quality standards, and the impact would therefore not be significant.

In contrast, the concentration modeling method used to estimate annual averages took into account the different annual capacity factors, which were also used in developing the annual emissions estimates shown in Table 4.5-23 of the DEIR. Thus, the changes in estimated annual-average concentrations of nitrogen dioxide and sulfur dioxide from the Potrero plant, as shown in Table 4.5-29 (column Titled "1999 Analytical Maximum") of the DEIR, are roughly proportional to the annual emissions changes shown in Table 4.5-23. The resulting maximum annual concentrations of these pollutants would be less than the corresponding standards, and the impact would therefore not be significant.

U32 As explained in response to Comment U31, the changes in annual emissions estimates shown in Table 4.5-23 of the DEIR are reflected in changes in annual-average concentration estimates shown in Table 4.5-29 (not for lesser averaging periods).

U33 See response to Comment F29.

U34 Although there is no standard significance threshold for cancer risk, the California Air Pollution Control Officers Association (CAPCOA) has established the level of 10 in a million for the Air Toxics “Hot Spots” legislation (AB2588) as a conservative significance threshold for assessing health effects. This level was identified in the DEIR under Significance Criterion #3 on page 4.5-50. The DEIR takes into consideration the changes in cancer risks from the plants in future years under divestiture, and it states on pages 4.5-71 and 72 that cancer risks would change in proportion to the amount of fuel use that is caused by increases in energy generation. The changes in carcinogenic risks that are reported in the DEIR take into consideration the additional fuel use. The incremental risks from the PG&E plant emissions under divestiture are shown on Table 4.5-34 of the DEIR. These incremental risks are no greater than 0.1 in a million. The cumulative health risks which are reported in response to comment B6 show that the health risks, including other proposed plants near the Pittsburg and Contra Costa facilities, are also less than one in a million. These minimal incremental health risks are not cumulatively considerable (even in light of the existing setting of concern) since they are *de minimus* conditions, i.e., the environmental conditions would be essentially the same with or without the project.

The comment refers to studies that indicate higher cancer levels for certain population sectors. However, none of the studies indicate the causes of these increased rates, nor do they establish a linkage between ambient air pollution levels in the region and health effect endpoints.

U35 Table 4.5-10 of the DEIR shows that in 1992 and earlier, measurable emissions of metals and PAHs, as well as benzene and formaldehyde, occur as a result of burning fuel oil and natural gas in the steam boilers. Annual emissions of these substances in 1987 are the greatest, because of greater use of fuel oil. In 1990 and 1992, annual emissions of metals and PAHs decrease, and for some pollutants, the emissions are below measurable levels, which is indicated by the dashed line in the table entry. The levels that are below measurable levels vary by pollutant, partly because of different measurement techniques for each pollutant. However, any trace quantities below measurable levels are so low that, even as a total, they would not contribute to the exposure level risks in any measurable amount, which is less than 0.1 in a million. These emissions again would occur as a result of burning fuel oil for part of the year and would not contribute to chronic exposure levels. For 1995, the table shows emissions of benzene and formaldehyde, because only natural gas was burned in the boilers, due to BAAQMD Regulation 9, Rule 11. Annual emissions from the standby turbines at Potrero are immeasurably small and do not significantly affect total annual emissions from the plant. Thus, after 1995, the toxic pollutants of concern for chronic exposure are benzene and formaldehyde.

The DEIR (pages 4.5-71 and 4.5-72) states that annual emissions of benzene and formaldehyde for 1999 and 2005 will increase because of increases in annual natural gas usage. The health risk changes from these emissions changes in 1999 and 2005 are shown in Table 4.5-34. The table shows that at the Potrero plant, maximum cancer risks would increase from 0.17 in a million in 1999 Baseline to 0.23 in a million for 1999 A-Max. Under the 2005 A-Max scenario, the maximum risks are estimated to increase to 0.28 in a million. These maximum risk estimates are well below the significance threshold of 10 in a million.

U36 Table 5.1 is a list of existing, proposed, and planned projects that would be located within a one-mile radius of each of the power plants, including the Potrero plant. In the case of the Potrero plant, the information was provided by the San Francisco Planning Department and the Port of San Francisco (see response to Comment F51 regarding additions to Table 5.1). Because no site has been identified and no specific project proposal for a new facility has been received, it was not appropriate to include such a speculative project in Table 5.1. However, the DEIR does assess the cumulative environmental impacts of a new power plant in San Francisco. The 2005 Cumulative Analytical Maximum Scenario assumes construction and operation in or near San Francisco of new generation facilities totaling 480 MW. Section 5.3.3 (commencing on page 5-38) examines the cumulative impacts of Variant 1, which includes construction of a new 240 MW power plant in northern San Mateo County or within the City and County of San Francisco. The discussion in Section 5.3.3 acknowledges that the plant could be located on the same site as, or adjacent to, the Potrero Power Plant, and could be considered an expansion of that plant.

If the Potrero Power Plant were repowered, for cumulative analysis purposes, the impacts would be essentially the same as the impacts identified for construction of a new 480 MW at or near the Potrero plant. See response to Comment U37 for additional information. Project-specific impacts of repowering the Potrero plant or constructing new generating facilities would be evaluated in the project-specific environmental review that would be required under CEQA at the time such a project were proposed.

U37 As noted in response to Comment U36, the DEIR does in fact anticipate that the additional generating capacity could be built adjacent to or on the Potrero Power Plant site. The commenter correctly cites the DEIR text regarding a new owner's interest in repowering the Potrero Power Plant. Based on projected demand, the DEIR forecasts that an additional 480 MW of generation would be needed by 2005 to support the closure of the Hunters Point Power Plant. While the new owners of the Potrero Power Plant might elect to expand capacity at the plant, they would only do so if construction of any other proposed new plant supplying 480 MW did not proceed. There are several reasons for this. From a regulatory standpoint, public agencies with jurisdiction over new generating facilities, such as the Bay Area Air Quality Management District (BAAQMD) and the CEC, have demonstrated a reluctance to approve excess generating capacity for environmental and other reasons. For example, if the existing Potrero Power Plant were to continue operating, a new 480 MW facility were constructed, and the Potrero Power Plant Units 1 and 2 were repowered, San Francisco would have generating capacity beyond its anticipated demand in 2005. In the unlikely event that significant excess generating capacity were to be approved in San Francisco, the Potrero Power Plant owner would be precluded from exporting excess power to other markets due to the same transmission constraints that limit the amount of power that can be imported into San Francisco. Within the San Francisco market, since the lowest bidder would prevail, power generated at the Potrero Power Plant's older, less efficient (and hence more costly) units would be unable to compete with newer generating facilities. Thus, even absent the regulatory impediments, there would be strong economic disincentives for the owner of the Potrero Power Plant to expand its capacity if other new 480 MW facilities were also built.

The DEIR examined the potential 2005 cumulative environmental effects from continued operation of the Potrero Power Plant along with the addition of a new 480 MW power plant. The resulting modeled capacity factors are presented in Table 5.2 on page 5-17. For the reasons discussed above and in response to Comment U36, this analysis also covers the potential environmental effects that would result from repowering of the Potrero Power Plant.

U38 The cleanup of potentially contaminated soils at the plant sites, a beneficial environmental impact, could be advanced by the project. No specific remediation plan has been proposed at this time and the nature and extent of any remediation have not been determined. Soil remediation activities have, in general, the potential to affect surface water quality since the work typically includes disturbing soils. However, as explained on page 4.4-14, soil remediation activities are highly regulated and it is expected that the regulations for erosion and water quality control described in Section 4.3 and the regulations governing hazardous wastes described in Section 4.9.1 would be sufficient to protect water quality so that any impacts would be at a less-than-significant level. Please also see responses to Comments F40 and F41.

U39 The EIR does not claim to substitute the NPDES permit for an environmental analysis. It does, however, assume that the RWQCB issued the permit conditions such that no significant impact to water quality would occur from operation of the facilities at the maximum generating capacity of each plant. Therefore, the continued compliance with those conditions by the new owners, regardless of the plant operational levels, would result in less than significant impacts.

U40 The plant operating conditions reasonably foreseen and analyzed in this EIR project less-than-significant impacts on water quality. There is no reason to believe that new owners of the plants would have any increased tendency (over PG&E) to violate applicable permits. If the RWQCB decides at any point in the future that the operating conditions are detrimental to the environment or that there is a reason to suspect that the plant will not be able to meet discharge requirements that adequately protect marine resources, the RWQCB would modify its permit conditions. The RWQCB, as a trustee and regulatory agency, is properly entrusted with this role by the state.

U41 The DEIR does conclude that air quality impacts would be significant. Specifically, the DEIR concludes that the project would result in power plant NO_x emissions that are sufficiently different from those included in the regional air quality plan, and therefore, the project can be determined to be inconsistent with that plan. The DEIR further concludes that this impact would be unavoidable (albeit temporary) (page 4.5-81). The commenter is correct in noting that increasingly stringent NO_x controls would likely be installed, over time, to reduce overall power plant NO_x emissions with or without the project, but the commenter calls for an accelerated schedule for installation of these controls. However, an implementation schedule has already been established through BAAQMD Regulation 9, Rule 11, which presumably represents the most aggressive, and yet feasible, schedule possible considering such factors as cost and reliability issues.

U42 Please see responses to Comments F30 and 1-12. If the Potrero plant were repowered, the repowered facility would be subject to BAAQMD Rules and Regulations, which may require implementation of Best Available Control Technology (BACT). The EIR's use of the Analytical Maximum capacity factors for the plants under new ownership ensures that emissions estimates were not minimized, and instead are likely overstated. The air quality analysis presents and analyzes data in a straightforward manner that meets or exceeds the requirements of CEQA and pertinent case law.

CPUC PUBLIC MEETING COMMENT SHEET

Name: Richard and Sandy Baldwin
Address: 233 Heron Dr.
Pittsburg, CA
Telephone: (529) 473-1781

Comment: The concerns about PG&E and the power plant in Pittsburg exist on more than one level, the most dramatic and certainly the one that pertains to the most people relates to the impact on our environment and more specifically the impact on the health of the citizenry that live within close range of the plant. I am convinced that the studies have not covered this with enough of a microscope to assure us that all bases have been covered. I am very worried about it, but I will leave the details of studying this to those more expert than myself. My concerns have to do with social responsibility and lack of same that has gone into the study of the problem.

Pollution comes in many forms, my concern has to do with sound pollution and what the roar of the plant has done to my serenity, how it has impacted my life and living system.

I have lived in Marina Park for almost 2 years and our primary concern when we chose to purchase here was the neighborhood, how stable was it. The diversity of people in the community was a draw for us because we had felt so isolated in suburbia. We were missing out on exposure to other cultures and people with divergent issues, divergent ethnicity. We have been very content with that part of the experience. The pain has come with the deafening roar of the power plant. [Begin V1]It robs us of an outside life, patio pleasure, of sleep that is sound and uninterrupted; of serenity in our own home because of the silt that accumulates on tables; in curtains, on tables, disguised as dust.[End V1] [Begin V2]But most importantly, the continuous roar and when I hear of expansion and the fact that the Pittsburg plant is not state of the art and that more and more pressure is going to be placed upon it, that means to me, more roar, more silt and a lack of concern that PG&E is willing to give it.[End V2] [Begin V3]We have a community here, there is plenty of open, unencumbered territory for use as land for a power plant. It was suggested as an alternative at the meeting. Why? Why? Why? Must the little guy who is not a corporation, who doesn't come with credentials that/will make a dent in the large, very large, utility. WHY...must he bite the bullet and endure? I don't think so, I believed that that there are alternatives and I am confident that PG&E has the resources and the willingness to explore them, to assure that the people who daily rely upon them for their power source, will also be able to find some common ground to solve the problems that so trouble the residents of Marina Park. [End V3]

[Begin V4]

I look forward to future discussion and will not give up in an effort to get the problem solved. The quality of life for the citizens of this area and for that matter, all citizens, should be first and foremost on the minds of the utility that serves us. Social responsibility begins with them. It must.

[End V4]

INDIVIDUAL(S)

V. RICHARD AND SANDY BALDWIN

V1 The Pittsburg Power Plant has been in operation since 1954. This EIR does not address the environmental effects associated with construction and operation of the Pittsburg plant; rather, it addresses the potential environmental changes that would result from PG&E's sale of the plant and continued operation of the plant by a new owner. As an example, the EIR examines the projected increase over existing noise levels from the Pittsburg Power Plant that would potentially occur with the sale of the plant to another operator. The analysis concludes that, while operation of the plant could increase under the project, which could result in increased noise levels to some degree, the potential change in noise levels would not be significant. Projected increases in PM-10 (dust) would also be less than significant. Please refer to Sections 4.5 and 4.10 of the DEIR, and the response to Comment W1, for additional information on these impacts.

V2 Please see response to Comment V1.

V3 The commenter appears to be advocating that the Pittsburg Power Plant be closed and a new power plant built at another location to replace the generation of the Pittsburg plant. Such a scenario is not a true alternative to the sale of the Pittsburg Power Plant, which, if not sold, would continue to be owned and operated by PG&E (a scenario analyzed as Alternative 1 in Chapter 6 of the DEIR). Furthermore, the Pittsburg plant is designated a "must run" plant by the ISO for reliability purposes, and could not be closed until it is no longer needed for system reliability. For these reasons, the DEIR does not and need not evaluate the potential environmental effects of closing the Pittsburg Power Plant and building a new plant at a different location. As noted elsewhere (see responses to Comments B6, B15, and O1, as well as Figure B6), several new power plants (PDEF and DECP) are proposed to be located in the Pittsburg-Antioch area. Even with these new plants, the Pittsburg Power Plant is expected to continue operation.

V4 Comment noted.

CPUC PUBLIC MEETING COMMENT SHEET

Name: Arch J. Chaplin
Address: P.O. Box 4817
Antioch, CA 94531
Telephone: (925) 777-9636

(see attached)

8-25-98

To CPUC:

[Begin W1]

Our principal concern about the sale of the PG&E power plants is regarding the Boat Wash Program that has been in effect for 20 years or more.

Will the new owners continue the same program as it now exist?

If the new owners operate the plants at a higher level we feel that this in itself is justification for the continuation of the program.

Even if the new owner don't crank up production we feel very strongly that the Program mentioned above must been maintained on a regular and continuing basis.

Your support would be greatly appreciated.

[End W1]

Arch J. Chaplin
P.O. Box 4817
Antioch, CA 94531

Mark Allen
2974 Delta Fair Blvd. #319
Antioch, CA 94509

Robert B. Clune
252 Heron Dr.
Pittsburg, CA 94565

Harry Lent
146 Pelican Loop
Pittsburg, CA 94565

Edward R. Wright
P.O. Box 1632
Pittsburg, CA 94565

Bart Fisher
30A Lavritzen Ln
Antioch, CA 94509

Sandy & Dick Baldwin
233 Heron Drive
Pittsburg, CA 94565

Rie Carver
51 Marina Blvd Ste A
Pittsburg, CA 94565

Jim LaFond
52 Montrose Ct
Brentwood, CA 94513

Art O'Reilly
8 Tyr Ct.
Pleasant Hill, CA 94523

Larry Wheeler
4648 Arabian Way
Antioch, CA 94509

Danny & Pat Van Allen
3760 Northridge Dr
Concord, CA 94518

W. ARCH J. CHAPLIN *et al.*

W1 The commenter is concerned that the boat wash program at the Contra Costa and Pittsburg Power Plants, used as a means to mitigate fallout-type particulate (FTP) from these plants, continue and wants to know what new owners of these plants would be required to do about FTP. The DEIR clearly addresses these issues beginning on page 4.5-13 and proposes, via Mitigation Measure 4.5-4 (see page 4.5-76), a means to ensure that new owners will continue to address FTP impacts by having a program to verify and process claims related to FTP. The mitigation measure also requires the new owners of the Contra Costa and Pittsburg plants to develop procedures to minimize FTP emissions in future operations. In other words, boat owners will continue to be able to receive compensation for washing their boats if they can demonstrate that their boats need to be washed as a result of damage from FTP emissions from these two plants. This Mitigation Measure (4.5-4) is suggested by the EIR even though the analysis determined that the sale of the plants, and the possible resulting loss of PG&E's voluntary FTP cleanup programs, would not result in a significant environmental impact.

CPUC PUBLIC MEETING COMMENT SHEET

Name: Anthony/Sara Chavez
Address: 218 Pelican Loop
Pittsburg, CA 94565

[Begin X1]
Comment: We do not feel that heavy industrialization is the key to redevelopment of a beautiful Delta City like Pittsburg, CA. Are we using Pittsburg, PA. as a format??? Pittsburg is already too industrialized. PG&E has not been a good neighbor over the nine years we have resided here. Black/grey residue, loud irregular pressure releases (any time day or nite). Environmental alerts at both Dow Chemical and PG&E. Pittsburg does not need pollution, rolling semi's, torn-up streets and diminished real estate values.
[End X1]

[Begin X2]
Our retirement move to this community was motivated by peace, serenity, water and friendly community living.

The City of Pittsburg will shatter all positive hopes for further suburban development if they allow this proposed power plant to be added to a top-heavy industrialization now in place.
[End X2]

X. ANTHONY AND SARA CHAVEZ

X1 Please see the response to Comment V1.

X2 The commenter appears to incorrectly believe that this EIR is concerned with the new power plants proposed to be located in the Delta area. This EIR is concerned only with the sale of PG&E existing power plants. Please see the response to Comment B15 regarding the cumulative impacts of this project together with development of the PDEF and DECP Power Plants proposed in the Pittsburg vicinity.

19 SEP 1998

BRUCE KANESHIRO, PROJECT MANAGER
C/o ENVIRONMENTAL SCIENCE ASSOCIATES
225 BUSH STREET, SUITE 1700
SAN FRANCISCO, CA 94104

SUBJECT: PROPOSED DIVESTITURE OF ELECTRIC GENERATION ASSETS BY PACIFIC GAS AND ELECTRIC COMPANY, APPLICATION NO. 98-01-008

AFTER REVIEWING THE EIR REPORT AND ATTENDING THE CPUC PUBLIC MEETING ON COBB MOUNTAIN, CA., I HAVE SOME COMMENTS TO MAKE:

[Begin Y1]
1. THERE SEEMS TO BE ABSENCE OF ANY REVIEW OF THE IMPACT TO OPERATIONS WITH ALTERNATE FUELS, IE., NATURAL GAS, CRUDE OIL, PRICES. SOME OF THE FACILITIES ARE ALREADY SETUP FOR ALTERNATE FUELS. [End Y1]

[Begin Y2]
2. AS A GOOD DEAL OF THE TIME, THERE IS A TEMPERATURE INVERSION AT APPROX 3000 FT MSL, NOISE VALUES CAN CHANGE IN AMPTITUDE AND BE TRANSMITTED SOME DISTANCE. IN ADDITION, WHEN A CLOUD CONDITION ALSO IS AT THE APPROX SAME ELEVATION, NOISE OVER 50 Db CAN TRAVEL SOME DISTANCE. WHEN STACKING OCCURS, THIS NOISE CAN IMPACT MUCH OF THE COBB MTN AREA. IN THE PROPOSED EIR AND THE PUBLIC MEETING, NO MENTION WAS MADE ON THIS SUBJECT. [End Y2]

[Begin Y3]
3. VERY LITTLE WAS MADE OF THE 50+ WEEKLY SEISMIC ACTIONS WE HAVE HERE ON COBB MTN. THIS NEEDS TO BE ADDRESSED MORE. [End Y3]

[Begin Y4]
4. THE ONLY DISCUSSION I COULD FIND ABOUT REINJECTION PROGRAMS WAS THE PROPOSED TWO PROJECTS PLANNED BY SANTA ROSA, NOTHING ABOUT THE CURRENT LINE FROM THE CITY OF CLEARLAKE, CA. SEEMS IT COULD HAVE AN IMPACT. [End Y4]

[Begin Y5]
5. LASTLY, BUT NOT THE LEAST, IS THE SUBJECT OF BANKRUPTCY AND/OR ABANDONMENT OF POWER SITE AND THE RESTORING OF THE LAND TO THE ORIGINAL NATURAL CONFIGURATION, IE. PROFORMING BOND TO INSURE THE RESTORATION. MANY RESIDENCE HAVE HEARD RUMORS OF A SALE, AS BEING THE CHEAPEST WAY TO GET OUT WITHOUT THE COST OF RESTORATION, THEN BANKRUPTCY. WE WOULD LIKE TO SEE THIS SUBJECT COVERED IN DEPTH. [End Y5]

IF YOU HAVE ANY QUESTIONS, PLEASE CONTACT ME.

REGARDS,

E.J. (ERV) GALLAGHER, Fed P.E.

Y. ERV GALLAGHER, FED P.E. (of Airspace Systems Aviation Consultants)

Y1 It is assumed that the commenter's concerns are focused on the Geysers units. The Geysers units can operate only on geothermal steam. They cannot use any other alternate fuels such as natural gas or fuel oil. For the fossil-fueled steam turbines at Pittsburg, Contra Costa, and Potrero, it is foreseen that natural gas prices are likely to remain below comparable fuel oil prices in the future. In addition, Bay Area Air Quality Management District (BAAQMD) rules strictly limit fuel oil use in these units. The Potrero combustion turbines use distillate oil because natural gas use is not currently feasible.

Y2 Because of new technology installed at the Geysers in recent years, stacking problems have largely been eliminated, and are not expected to increase as a result of the project. (Please see response to Comment H54 of the Lake County Air Quality Management District regarding steam stacking events at the Geysers Power Plant.) In addition, while it is true that temperature inversions and cloud conditions can affect the distance that noise travels, these conditions will persist no matter who owns the generating units. In other words, the project examined in this EIR (the sale of PG&E power plants) will have no effect on how often the noise events occur, or on the atmospheric conditions that affect how far the noise will travel.

Y3 This issue is addressed in Section 4.3.2, beginning at the bottom of page 4.3-6 of the DEIR, and is further discussed in the responses to comments H11 and HH1.

Y4 The current reinjection program is discussed in Impact 4.3-2, from page 4.3-12 to 4.3-14, and in Section 5.2.4 starting on page 5-9 of the DEIR.

Y5 Please see response to Comment K1.

CPUC PUBLIC MEETING COMMENT SHEET

Name: VERNON HUFFER
Address: 188 PELICAN LOOP
PITTSBURG
Telephone: (925) 432-0390

[Begin Z1]
Comment: NO MENTION HAS BEEN MADE OF THE POSSIBILITY OF REDUCING THE NOISE GENERATED BY THE PITTSBURG PLANT I REALIZE THAT DUE TO THE SIZE OF THE BOILERS IT COULD BE EXPENSIVE HOWEVER IT SHOULD BE POSSIBLE TO MUFFLE THE STEAM RELEASES THOSE AT NIGHT ARE ESPECIALLY ANNOYING.
[End Z1]

[Begin Z2]
A FEW YEARS AGO I CALLED THE PG&E SAFETY OFFICE TO COMMENT THAT THEIR DOCK WAS NOT WELL LIGHTED AND SO CONSTITUTED A NAVIGATION HAZARD. I WAS TOLD THAT EVERYTHING WAS LEGAL AND A COUPLE HUNDRED WATTS OF POWER (LIGHT0 WAS NOT NEEDED.
[End Z2]

Z. VERN HUFFER

Z1 Concerns about existing noise levels at the Pittsburg Power Plant are beyond the scope of this EIR, which is concerned strictly with the environmental effects associated with the proposed project. Therefore, the EIR does not examine the effect of existing noise from the Pittsburg Power Plant (except establish the environmental setting against which impacts are judged), but evaluates the projected increase over existing noise levels that would potentially occur with the sale of the plant to another operator. The analysis concludes that, while operation of the plant could increase under the project, and could result in increased noise levels, the change in noise levels would not be significant. Please see the discussion under Impact 4.10-2, pages 4.10-10 through 4.10-15 of the DEIR, for more detailed information.

Z2 This comment does not pertain to the adequacy of the DEIR or to any potential environmental effects that would result from implementation of the proposed project.

CPUC PUBLIC MEETING COMMENT SHEET

Name: PAULETTE M. LAGANA
Address: c/o CAP-IT
P.O. BOX 1128
PITTSBURG, CA 94565-2021
Telephone: 925-439-2227

Comment: I have several concerns regarding the divesting of the Pittsburg and Antioch plants.

[Begin AA1]
1. It is a concern that the Pittsburg plant did not have as an option that the plant would close once replacement power became available, such as the option available to the Hunters Point plant. This is especially true since there are two new power plants proposed for Pittsburg, (1) Pittsburg District Energy Facility [PDEF] and (2) Cal-Pine facility.
[End AA1]

[Begin AA2]
2. It is a concern that the proposed operation capacity factor for Pittsburg is baselined at 31% and analytical maximum at 68%. Antioch is baselined at 36% and analytical maximum at 80%. What is not detailed is the increase in noise and traffic and the effects on cumulative impact.
[End AA2]

[Begin AA3]
3. It is a concern that the Pittsburg plant will be considered an essential plant on the power grid and, therefore, will not be considered eligible for closing down the plant.
[End AA3]

[Begin AA4]
4. The technology used in Pittsburg and Antioch is older technology which is less efficient. This older technology has a negative impact on water, air, soil, and humans.
[End AA4]

[Begin AA5]
5. Will the new owners of the Pittsburg & Antioch plants be required to guarantee that no jobs will be lost?
[End AA5]

[Begin AA6]
6. There is a concern that there is an overlap in the radius of air quality impacts of the five plants -- Pittsburg, proposed PDEF plant, Cal-Pine/DOW, proposed Cal-Pine, and Antioch. This possible radius overlap is not clearly defined nor investigated.
[End AA6]

[Begin AA7]
7. The hazard impacts appear to be underestimated. The data does not reflect the true picture. In other words, it is technically correct but inaccurate in its assessment of noise, emissions and traffic.
[End AA7]

[Begin AA8]
8. Background risk needs to be considered for this assessment to be more accurate.
[End AA8]

AA. PAULETTE M. LAGANA (c/o CAP-IT)

AA1 The commenter is concerned that the EIR did not consider in its analysis the possibility that the Pittsburg Power Plant could be closed, as was considered with the Hunters Point Power Plant. The closing of the Hunters Point plant was considered a possibility in light of the June 9, 1998 agreement between PG&E and the City and County of San Francisco, in which PG&E agreed to shut down the plant when it was no longer needed for system reliability. Without a comparable agreement between PG&E (or the future plant owners once such party is known) and the local government, the prospect that any of the plants proposed for divestiture may close in the near future is too speculative to consider in the EIR. (As noted in the DEIR, all of the plants proposed for divestiture are designated as "must-run" plants for system reliability by the Independent System Operator [ISO].)

AA2 The commenter does not state the nature of her concern about the baseline and analytical maximum capacities assumed in the analysis of the Pittsburg and Contra Costa Power Plants. However, the baseline for these plants is based on an economic model that reflects operation of the Delta plants in 1999, and includes projections on future demand, future natural gas prices, operating expenses, regulatory restrictions, and a host of other assumptions which are documented in Attachment G of the DEIR. As noted in the DEIR, in order to conservatively depict the greatest potential project impacts in 1999, the 1999 Analytical Maximum scenario assumes that the plants would operate at their maximum capacities, within the parameters of their existing air permits and water discharge permits. This scenario also takes into account other limiting factors, such as scheduled and forced outages of units for maintenance; contractual limitations, including must-take contracts that favor power generated by qualifying facilities; and demand constraints (i.e., the finite demand for electricity at any particular time on any give day). Contrary to the commenter's assertion, detailed discussions on project-related increases in traffic and noise are presented in Sections 4.6 (pages 4.6-1 through 4.6-5) and 4.10 (pages 4.10-1 through 4.10-16), respectively, of the DEIR. An entire chapter (Chapter 5, pages 5-1 through 5-42) is devoted to an analysis of cumulative impacts. Please refer to these sections of the DEIR for additional information.

AA3 The Pittsburg Power Plant is currently designated as a "must-run" facility by the ISO and must remain on-line during certain times in order to ensure system reliability. However, the ISO will annually re-evaluate its determination of must-run status for the Pittsburg plant and all other plants designated as must-run. The ISO bases its must-run determination on several factors, but generally chooses the most efficient generating units available to meet the reliability requirement. As new, more efficient power plant units are constructed and come on-line in the Contra Costa County area (if that occurs), the ISO would likely choose one or more of such new units for designation as must-run, and would remove such designation from any Pittsburg unit. Thus, no legal obligation would then exist to prevent the Pittsburg plant from being retired.

AA4 The power-generating equipment used at the Pittsburg and Contra Costa Power Plants is not the subject of this DEIR, which is focused on the potential environmental effects that would result from divestiture of the plants by PG&E. It should be noted that an existing regulatory structure governs and limits potential emissions to water, air, and soil by these power plants. For example, the Bay Area Air Quality Management District (BAAQMD) regulations impose requirements on the plants that limit their air emissions, such as Regulation 9, Rule 11, which requires the use of cleaner-burning natural gas to fire the generator boilers. Stormwater runoff and water discharges are regulated by the Regional Water Quality Control Board. For additional information on existing regulatory controls at the Delta power plants and potential impacts that would result from implementation of the project, see Sections 4.4, Water Resources; 4.5, Air Quality; and 4.9, Hazards, of the DEIR.

AA5 Although the new owner of the Pittsburg and Contra Costa Power Plants (the Delta plants) would not be required to guarantee that no jobs would be lost, they would be required to enter into an Operations and Maintenance (O/M) Agreement with PG&E for PG&E to operate and maintain the plants for two years following closing of the sale. It is PG&E's intent to staff the plant during the O/M agreement period with existing PG&E employees. After this period, the new owner would develop a staffing plan to operate and maintain the facility. Although it is unknown at this time if the future owner would increase or decrease the number of employees at the Delta plants, as noted in the DEIR, it is likely that operational levels at the plants would increase in the future. It is therefore unlikely that a substantial number of jobs would be lost at those plants.

AA6 Please see responses to Comments B6 and R11, and pages 5-39 through 5-42 of the DEIR.

AA7 The issues raised by the commenter are addressed in the DEIR. Noise impacts are discussed in Section 4.10, beginning on page 4.10-10. Impacts of emissions are discussed in Section 4.5, beginning on page 4.5-51. Traffic impacts are discussed in Section 4.6, starting on page 4.6-2.

AA8 When evaluating health risks from exposure to emissions from industrial sources, especially risks from exposure to carcinogens, the background risk is usually not included in the analysis, because there typically is little or no information available on overall risks from exposure to toxics in a region. However, in the past few years, BAAQMD has been gathering information on exposure to air toxics. The Agency has relied on toxics emissions inventories that were prepared for most of the stationary industrial facilities in the Bay Area as part of the Air Toxics "Hot Spots" legislation (AB 2588), and also on health risk analyses that were carried out for sources with significant toxics emissions. This information was supplemented with air toxics measurements. Based on these data, the BAAQMD combined the health risk results and estimated that the maximum health risk in the air basin from industrial facilities is about 300 in a million. This health risk estimate does not consider other factors not related to industrial sources, such as mobile sources, diet, smoking, lifestyle, and exposure to chemicals by other pathways besides the air pathway. As reported in the DEIR, PG&E's maximum contribution to health risks that was included as part of the total airshed health risk analysis was less than one in a million.

In any event, the EIR focused primarily on the risks posed by the project (sale of power plants) since the purpose of the California Environmental Quality Act is to consider the change to the environment that will be affected by the project. The project's maximum contribution to health risks were also found to be less than one in a million (pages 4.5-72 through 4.5-74).

CPUC PUBLIC MEETING COMMENT SHEET

Name: Harry Lent
Address: 146b Pelican Loop
Pittsburg, CA 94565

Comment: Please see attached sheets

August 28, 1998

Bruce Kaneshiro
Project Manager
Environmental Science Associates
225 Bush St.
Suit 1700
San Francisco, CA 94104

[Begin BB1]
After attending the CPUC meeting at the Pittsburg Yacht Club on Aug. 25th concerning the sale of PG&E's Pittsburg power plant I came away with the feeling that very little concern had been given to the problem of noise polution. We live approximately 3000' SE of the plant and noise, at the present production level, is a serious problem. In the summertime when the plant is operating at or near capacity the noise level is such that we must close our windows and turn on the airconditioning in order to sleep. This makes neither environmental or economic sense since our normal cooling evening breezes are free and ecologically safe. Walking, playing or just sitting in the back yard visiting with friends is less enjoyable because of the noise. Now you're considering a change which will almost certainly result in a doubling of electrical production and its partner noise. At the meeting when questioned about this one of the moderators replied that is would 'average out'. What could that mean?

We have lived in our home for over nine years and were aware and accepted the noise at its present level when we purchased. Now you are considering a move which could very well force us to move away from our friends if the noise level becomes untenable.
[End BB1]

[Begin BB2]
PG&E has had many incidences of personel or mechanical failures which have resulted in the release of high pressure steam. The noise resulting from this, I am sure, exceeds any generally accepted standards. These releases have gone on for hours at a time and the only way to cope is to leave the area. They also had a boiler explosion in 1997 that besides creating tremendous amount of noise contaminated a large area with asbestos. Common sense tells me that the more you use a piece of machinery the more chance you have of these types of failures.
[End BB2]

[Begin BB3]
It was stated at the meeting that noise levels had been monitored and found not to be a problem. At what level was the plant operating when there readings were taken? This imformation should be readily available. If it was at less than peak production another more comprehensive study should be made to give you a truer picture of the problem.
[End BB3]

[Begin BB4]
A great deal of effort and money has been put into the New York Landing area rehabilitation. What you're considering will most certainly lower the quality of our life and lead to lower property values. We don't deserve this. We've worked too hard and long to reach our present aesthetic and cultural level and have high hopes for the future. Eccessive noise is as much a pollutant as particulates or cooling water that is pumped back into the river at too high a temperature. Eccessive noise is a significant problem for the residents of this area.
[End BB4]

Harry Lent
146 Pelican Loop
Pittsburg, CA 94565
925-439-5993

BB. HARRY LENT

BB1 Noise impacts of the proposed sale of the Pittsburg Power Plant are addressed in Section 4.10 of the DEIR. The analysis included noise monitoring at the plant's eastern boundary during summertime operations. Noise monitoring revealed that summertime operations of the plant are within the County's land use compatibility guidelines for industrial land uses bordering residential land uses

The analysis in Impact 4.10-2 of the DEIR indicates that increased frequency of generation operations at the plant would not result in a significant noise impact, relative to noise and land use compatibility. Because power plant noise does not change substantially over a range of loads for each unit, the potential for increased noise would result from more frequent operation of multiple units. If a new operator wished to increase plant output over PG&E baseline operational levels, it could do so by either operating units at a higher capacity or operating more units simultaneously. However, given the time required to bring additional units on-line, an operator would have a tendency to increase output of units in operation before bringing additional units on-line. Because multiple unit operations currently occur within the land use compatibility guidelines of the County General Plan Noise Element, potential increases in multiple unit operations would be minimal (would not affect average noise levels) compared to existing operations that occur within County standards.

BB2 As stated in the Noise setting section of the DEIR, noise complaints from plant operations have primarily been the result of safety relief valves. Periodically, the automatic safety relief valves for the boilers are activated, resulting in the release of high-pitched noise levels for a short period of time. Currently, safety relief valves are activated very infrequently (estimated at two to three occurrences per year by the plant manager at the Pittsburg plant). The duration of these events is generally less than one minute and is a necessary function of power plants to avoid a boiler explosion.

Based on the relative infrequency and the short duration of these events, in addition to their importance relative to safety to plant workers and surrounding communities, the potential for increases in safety relief valve activation would not be considered significant. It is not foreseeable that major equipment failures would occur more frequently under new owners compared to PG&E ownership.

BB3 Noise impacts of the proposed sale of the Pittsburg Power Plant are addressed in Section 4.10 of the DEIR. The analysis included noise monitoring at the plant's eastern boundary during summertime operations. As stated on page 4.10-4 of the DEIR, daytime ambient noise measurements were conducted around the perimeter of the plant on July 2, 1998. At the time of monitoring, Units 5 and 7 were operating. These are two of the larger units of the plant. While monitoring events did not capture simultaneous operation of all units, such an event was a rare occurrence in 1998.

BB4 Please see response to Comment BB1.

Name: James B. MacDonald
Address: 274 Pebble Beach Loop
Pittsburg, CA 94565
(925) 439-7665

[Begin CC1]
Comment: The plants are currently allowed to burn diesel fuel under Emergency Conditions.

1. What constitutes Emergency Conditions?
2. How long can a plant operate under Emergency Conditions?
3. Consideration expected increased output of new ownership, what are long-term and short-term health risks while operating under Emergency Conditions at higher output levels, in each of the following categories: newborns, children, teenagers, adults, senior citizens, people with respiratory illnesses. [End CC1]

[Begin CC2]
Comment: Considering the higher output of new owners operating under normal conditions burning natural gas, what are health risks in each of the categories listed above.
[End CC2]

[Begin CC3]
Comment: Considering new status of diesel fuel emissions as toxic, will operations of new owners under Emergency Conditions exceed any legislated standards. Will plant emissions combined with other existing emissions violate any standards?[End CC3] [Begin CC4]If all existing Industrial-zoned areas within the City of Pittsburg become Heavy Industrial, will emissions levels exceed Standards?[End CC4]

[Begin CC5]
Comment: Considering new findings of particulate matter emissions as cause of Respiratory Illness, including death from asthma, what are health risks while plant is operating under normal conditions for each of the following categories: newborns, children, teenagers, adults, senior citizens, people with Respiratory Illnesses? Rate health risks of particulate matter for each of the categories under the following conditions: operating at higher output levels of new owners during Emergency Conditions, plant output emissions in combination with existing industries, potential future emissions if all industrial areas within City of Pittsburg become Heavy Industrial.
[End CC5]

[Begin CC6]
Comment: The City of Pittsburg's expectation and desire is that the lower cost of power, due to the new ownership of Pittsburg PG&E plant and other new planned power plants within the city, will be incentive for increased growth in the industrial base in the area, and that without lower cost locally-available power this could not happen. What is the expected effect this would have on an already over-burdened transportation infrastructure? What are expected health risks from diesel fuel emissions, due to increased rail and heavy truck traffic in the area, on each of these categories: newborns, teenagers, adults, senior citizens, people with Respiratory Illnesses? Rate health risks as above for transportation diesel fuel emissions in combination with increased level of industrial emissions.
[End CC6]

[Begin CC7]
Comment: Considering all of the scenarios and categories listed above; what risks can be expected for the two potential sites for a new Elementary School in the Downtown area? Site A--Next to St. Peter Martyr School on Montezuma Street. Site B--Between Railroad and Black Diamond from 10th and 7th Streets.
[End CC7]

[Begin CC8]
Comment: Considering all of the scenarios and categories listed above, what effect will emissions at “new owner” levels have on Central Valley/Sacramento Air Basin air quality? What will be effect on Central Valley/Sacramento Air Basin air quality if all industrial zoned areas go Heavy Industrial?
[End CC8]

[Begin CC9]
Comment: Considering all of the above; what would be the effect if a condition of sale of the Pittsburg PG&E plant was the new owners use best available technology to control air and noise pollution?
[End CC9]

[Begin CC10]
Comment: Considering all of the above; what would be the effect of new owners not using the property as a power generation plant and being allowed to do some of the following:
A. Residential Development, B. Wetlands/Open Space/Nature Reserve; C. Non-Industrial Commercial Property; D. Considering the existing Marine Dock facility and Storage Tanks the facility may be attractive to someone as a Marine Liquid Bulk Import/Export Facility. What options other than continued use as a power generation facility have been considered? How might these and other options affect the Environmental Quality in the Delta Region?
[End CC10

[Begin CC11]
Comment: Much of the heavy air pollution that affects the downtown Pittsburg are is very localized. Without an air monitoring station in place in downtown Pittsburg, how is CPUC making its conclusions on existing conditions in this area? How does CPUC intend to monitor effects in future and measure compliance? “Best Guess”?
[End CC11]

[Begin CC12]
Comment: Regarding sources of offsets; study designates two Air Basins--South Bay and North Bay. Assumption that offsets in North Bay Air Basin will have actual effect in Pittsburg area needs to be reexamined. Due to extremely heavy nature of Industrial output in Delta region, Carquinez Straights should be considered as separate Air Basin and offsets should be restricted to that area.
[End CC12]

[Begin CC13]
Comment: Considering the extremely high particulate matter pollution in the downtown Pittsburg area, stringent controls and mitigating measures should be enforced.
[End CC13]

[Begin CC14]
Comment: At a recent meeting of the CPUC regarding the PG&E Application for Divestiture; the staff indicated that the air quality in any given 24 hour period would not worsen but that there would be more “worse days” under the new ownership. The contention that this should be acceptable to the community, is ludicrous.
[End CC14]

CC. JAMES B. MacDONALD

CC1 Bay Area Air Quality Management District (BAAQMD) Regulation 9, Rule 11 prohibits PG&E from burning any fuel other than natural gas in the steam boilers, unless the plants are restricted from using natural gas under *force majeure*. A detailed discussion on emergency conditions under *force majeure* is given in footnote #6 on page 4.5-17 of the DEIR. Since 1994, there have been no emergency conditions requiring the use of residual fuel oil, and the PG&E plants have burned only natural gas in the boilers and expect to continue to do so in the future. If an emergency situation were to occur, diesel fuel would not be used, but residual fuel oil might be used for short periods. The acute and chronic health risks from such an emergency condition would be similar to the scenarios treated in the AB2588 health risk assessments (HRAs) that were carried out in 1992. In these HRAs, the maximum acute and chronic health risks (covering all categories of persons listed by the commenter) were shown to be less than the significance levels, which for carcinogenic risks are than 10 in a million and for acute and chronic hazard indices less than 1.

CC2 The health risks were evaluated for all of the maximum operating conditions using natural gas in the steam boilers and distillate in the combustion turbines.

CC3 There will be no diesel fuel emissions at the Pittsburg plant, since there are no provisions for using that fuel. The only power generators that can burn distillate, a derivative of diesel fuel, are the combustion turbines at the Potrero plant. These turbines are permitted to operate no more than 870 hours per year to supply power during times of peak demand. The health risks from burning distillate fuel in the combustion turbines at the Potrero plant were evaluated in the DEIR. The DEIR also evaluated plant emissions (at the plant's Analytical Maximum of operation) combined with existing background emission levels and found no significant impact (see pages 4.5-67 and 4.5-68).

CC4 The Pittsburg Power Plant site lies within the jurisdiction of Contra Costa County, and it is therefore the County's land use designations that govern land use planning on the site. The site is already designated in the County General Plan as Heavy Industrial. With respect to areas within the jurisdiction of the City of Pittsburg that are zoned for industrial use, the commenter's question does not relate to the adequacy of the DEIR or to potential environmental effects that could result from implementation of the proposed project. It would be speculative to conclude that all industrial-zoned lands within the City of Pittsburg would be rezoned for heavy industrial use. The DEIR in Chapter 5, Cumulative Impacts, includes and evaluates all projects proposed in the vicinity of the plants at the time of DEIR preparation.

CC5 There have been several studies published in the last several years that link particulate matter in the ambient air, especially fine particulate matter, to increased respiratory related ailments, including asthma, and cardiovascular disease. A number of these studies attempt to provide a quantitative link between the level of exposure and the degree of illness for various population sectors. However, it is difficult to accurately relate exposure levels to the extent of illness, partly because of confounding factors, such as the role of other pollutants and because of the wide range of susceptibilities for various sectors of the population. Also see response to Comments F62 and F74.

Even with these uncertainties, the EPA has promulgated a fine particulate matter standard (PM-2.5) to protect the public from exposure. The new PM-2.5 standards, which were promulgated in July 1997, were set to protect the most sensitive populations. The rationales used by the EPA to establish these new standards were also used to asses the impacts of fine particulate matter emissions from the PG&E plants.

The impacts of other existing plants and industries in the area were included by using the maximum particulate matter ambient air concentrations that were measured in the region as the background. These maximum measured values for the regions around the three plants, which are identified in Tables 4.5-29, 4.5-31, and 4.5-32, were added to the modeled concentrations from the PG&E power plants to determine the potential worst-case impacts. Using the maximum background is standard practice when conduct air quality analyses, and is very conservative, since a portion of the measured maximum levels may already include emissions from the existing PG&E plants. Thus, the reported total ambient air PM-10 concentrations may be double counting contributions from the PG&E plants.

Please also see the response to Comment CC4.

CC6 The cumulative analysis described in Chapter 5 of the DEIR identifies future projects in the area that may occur, none of which will generate significant increases in commercial traffic, including diesel operated trucks. Therefore, there are no measurable health risks expected from traffic related to these projects in conjunction with the sale of the Pittsburg plant.

Please also see the response to Comment CC4 and the DEIR's discussion of growth-inducing impacts beginning on page 4.2-7.

CC7 The DEIR reported the maximum health risk contributions from the plant in the area (see pages 4.5-29, 4.5-30 and 4.5-72). The risks from plant emissions were considered to be less than significant. The impacts at other locations, such as those identified in the comment, would be less than the reported maximum risks and would also be less than significant.

CC8 The issue of how emissions in the Bay Area can affect air quality in the Central San Joaquin Valley and Sacramento air basins has been the subject of much debate and study in the past few years. These studies are part of the Air Quality Attainment Plans that are being carried out for both the Bay Area and the San Joaquin Valley, and they include cumulative emissions in each airshed. This issue is complicated by difficulties in being able to accurately quantify emissions from all sources in the Bay Area and in being able to simulate the complicated atmospheric processes involved in the long-range transport of these pollutants. The main issue of concern for air quality in the Central San Joaquin

Valley involves the transport of pollutants that would affect ozone levels in the Valley. The principal ozone precursor emissions from the PG&E plants are nitrogen oxides. The DEIR states on page 4.5-17 that emissions of nitrogen oxides precursor emissions will be reduced from the PG&E steam boilers each year beginning in 1997 until a final reduction of 90 percent is reached by 2005. Thus, the project will not contribute to any cumulative impacts that ozone precursor emissions may have on air quality in the San Joaquin Valley. The commenter's concern for air quality impacts due to heavy industrialization of the area is not an impact of the project since such an occurrence could occur with or without the sale of the plants.

CC9 With respect to air pollutant impacts and the use of Best Available Control Technology (BACT), please see response to Comment U5.

As indicated in the Noise setting section of the DEIR, the Pittsburg plant currently operates within the noise compatibility guidelines of the County General Plan for a industrial land use bordering a residential land use. The analysis in Impact 4.10-2 of the DEIR indicates that increased frequency of operations at the plant would not result in a significant noise impact, relative to noise and land use compatibility. Consequently, there is no requirement (i.e., noise ordinance) or County policy (i.e., General Plan goal or policy) that would obligate a new owner to install additional noise control equipment.

CC10 The Pittsburg plant was assumed in the DEIR to continue operating as a power plant. It is noteworthy that the plant is designated by the Independent System Operator as a "must-run" plant for reliability purposes and the plant site is designated in the Pittsburg General Plan as UT (utility) and zoned for heavy industry. The options suggested by the commenter would require closure of the Pittsburg plant and its replacement by radically different (in three out of four proposed scenarios) operations. Please see response to Comment AA1 for a discussion of the reasons closure of the Pittsburg plant was not analyzed in the DEIR.

CC11 The EIR relies on the best available information to determine both background concentrations and incremental concentrations due to emissions from the Pittsburg Power Plant. For background concentrations, the EIR uses the monitoring data from the Pittsburg monitoring station, which is 0.7 miles south of the plant. Conventional modeling techniques were used to estimate incremental concentrations from the power plant at locations in the vicinity. The two values are added together and then compared to ambient air quality standards or applicable significance criteria (see Table 4.5-32 of the DEIR). Since the localized air quality impact of the project was determined to be less than significant, no mitigation or corresponding monitoring is required.

CC12 Since the project involves existing emissions sources, which are operated under air district permits, and since the estimated emissions increases would require neither permit modifications nor additional permits, no offsets would be required to offset the increases in power plant emissions described in the DEIR.

CC13 The DEIR identifies Mitigation Measure 4.5-5 (on page 4.5-81), which requires a modification of BAAQMD Regulation 9, Rule 11, or a revision to the existing permits to incorporate NO_x emission rate limits, which would apply to any new owner, in substantially the form and stringency in the current BAAQMD Regulation 9, Rule 11. Recent changes in Regulation 9, Rule 11 have banned the burning of fuel oil in the Bay Area steam boilers except for very limited testing and under force majeure natural gas curtailment. This recent revision is a strict measure to limit PM-10 from steam boilers because fuel oil combustion (which would be banned under Mitigation Measure 4.5-5) results in approximately three to four times more PM-10 than natural gas combustion (see DEIR page 4.5-52). No other significant air quality impacts are identified by the EIR.

CC14 The information referred to is contained in Table 4.5-33 on page 4.5-69 of the DEIR. This table indicates how PM-10 emissions would change if the Pittsburg Power Plant was operated at its Analytical Maximum capacity in 1999 and 2005. The table shows what PM-10 levels would result if the plant operated at Baseline or Analytical Maximum levels and if the area experienced worst-case meteorology on every day of the year (an impossible scenario). While the 1999 Baseline results show that 55 percent of the days have a maximum off-site effect of less than 5 micrograms per cubic meter ($\mu g/m^3$), for the 1999 Analytical Maximum, all days are above 5 $\mu g/m^3$. While operations at the Analytical Maximum would raise the PM-10 levels, even on days with worst-case meteorology, the contribution from the Pittsburg Power Plant would always be less than the significance criteria of 20 $\mu g/m^3$. The forecast for Analytical Maximum levels in 2005 is similar to the PM-10 levels in the 1999 Baseline (all forecast days would have average PM-10 levels below 10 $\mu g/m^3$), primarily because the analysis assumes that Pittsburg Units 1 and 2 would be retired before 2005.

CPUC PUBLIC MEETING COMMENT SHEET

Name: Meriel Medrano
Address: Box 676
Middletown, CA 95461
Telephone: (707) 987-0277

[Begin DD1]
Comment: Current air quality must be retained and maintained, and continued monitoring of the air quality. Present standards maintained, no exceptions.
[End DD1]

[Begin DD2]
Water quality, noise, health and safety or employees, wild life fish and game are all large concerns. Tax base is of concern.
[End DD2]

[Begin DD3]
I have resided in the area since 1971 and went through the discomfort of these plants being planned and built. It took much effort to be where they are today and I would not want to see any standards go backwards.
[End DD3]

DD. MERIEL MEDRANO

DD1 Nothing in this EIR is in disagreement with the statements of the commenter. Section 4.5 of the DEIR has specifically addressed these issues. Please see Section 4.5 of the DEIR for a complete discussion of air quality issues. In addition, please see the responses to Comments H9, H10, H33, H42, H68, T7, and EE3 for additional germane information on air quality issues and the commenter's concerns.

DD2 The DEIR addresses the commenter's concerns in the following sections and indicated responses to comments.

Water Quality – Section 4.4 of the DEIR; also see responses to Comments M1, O3, T1, T5c, T6, T10, and T12.

Noise – Section 4.10 of the DEIR; also see responses to Comments H54, J9, N11, and Y2.

Health and Safety of Employees – See Impact and Mitigation Measure 4.9-1 of the DEIR.

Wildlife, Fish and Game – See Section 4.7 of the DEIR; also see responses to Comments T1, T5b, T5c, T5d, and T5e.

Tax Base – See Section 4.11 of the DEIR; also see responses to Comments H15, I3, J6, K2, and N51.

DD3 Comment noted.

CPUC PUBLIC MEETING COMMENT SHEET

Name: Ronald E. Suess
Address: 1275 4th Street, No. 165
Santa Rosa, CA 95404
Telephone: (707) 541-0976

[Begin EE1]
Comment: This EIR should include a statement that acknowledges California will establish a hydrogen sulfide (H_2S) noncancer chronic reference exposure level (REL). The State believes H_2S poses a health risk to the public. The State has proposed 0.7 ppb (0.9 µg/m3) as the H_2S inhalation REL. This directly effects PG&E's Geysers Power Plant.
[End EE1]

[Begin EE2]
The effects can impact in two key ways. One, the establishment of the REL follows Air Toxics "Hot Spots" Assessment Guidelines. Such a low REL, 0.7 ppb, can trigger very detailed and costly health risk assessments for the Power Plant as per "Hot Spots" requirements. The cost of such assessments could adversely effect the Plant's ability to compete in the deregulated electric generating industry.
[End EE2]

[Begin EE3]
Two, the proposed REL could substantially increase H_2S abatement costs. California's ambient air quality standard is 0.03 ppm. It is based on threshold odor detection by humans. This standard plays a critical role on the mass emissions limits of H_2S from the Power Plant. The relationship between the mass emissions limits and the REL could necessitate changes in those limits. Hence, modifications to equipment and operations coupled with increases in abatement chemical consumption costs imperil the Power Plant's competitive position.
[End EE3]

I believe it is imperative to address the REL issue's impact on the Geyser Power Plant's portion of the EIR.

Ronald E. Suess, J.D.

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EE. RONALD E. SUESS, J.D.

EE1 A noncancer chronic reference exposure level (REL) for hydrogen sulfide (0.7 parts per billion, ppb) was proposed in October 1997, but has not yet been approved. Presently, there is no monitoring method capable of accurately measuring hydrogen sulfide at these low levels; thus, it would be difficult to enforce compliance with such a standard if one is promulgated. If a chronic REL is approved but no ambient air standard is established, PG&E or the new owner may be required to revise the health risk assessments (HRAs) for the Geysers plants as part of the biennial update of the AB 2588 Air Toxics “Hot Spots” submission. Such an HRA would involve estimating a new chronic hazard index from plant emissions by including hydrogen sulfide in the calculations.

EE2 All facilities that have prepared health risk assessments in California to comply with AB 2588 must submit biennial updates. These updates should include any revisions to toxics emissions from the plant and any revisions to the health risk assessment, if new reference doses are released by the California OEHHA. The cost for redoing the health risk assessment to address a new chronic exposure level that may be released by the Office of Environmental Health and Hazards Assessment (OEHHA) for hydrogen sulfide would be very small and would not affect the plant’s ability to compete in the deregulated generating industry.

Typically, when a health risk assessment is carried out to comply with AB 2588, screening models are used initially using hypothetical worst-case meteorology. The cost for completing a screening approach is usually less than $5,000. If the conservatively high screening results show significant impacts, then more detailed approaches are followed that use more realistic EPA Guideline dispersion models and meteorological data more representative of the site. Experience indicates that the cost for such a study should be no greater than $20,000. Clearly, these costs would not affect the competitive nature of geothermal electricity generation.

EE3 The Geysers plants are already controlling hydrogen sulfide emissions by using BACT. The residual emissions under normal operations are very small contributors to long term average (chronic) exposure levels of hydrogen sulfide in the region, and therefore would not be expected to cause any exceedances of a long term average standard. The issue that is more important is acute exposure to hydrogen sulfide from short-term releases during stacking and/or from well bleeds. These conditions are described more fully in the DEIR (pages 4.5-47 and 4.5-75). These short-term releases have occurred very infrequently in the past and are not expected to be major contributors to chronic exposure levels in the region. Furthermore, the releases are not expected to increase under divestiture. Therefore, the facilities should not require additional control over existing operations.

CPUC PUBLIC MEETING COMMENT SHEET

Name: DANNY VAN ALLEN
Address: 3760 NORTHRIDGE DR
CONCORD, CA 94518
Telephone: 925-671-2184

[Begin FF1]
Comment: THE CONTRA COSTA PLANTS PRODUCES LOUD NOISE SOME NIGHTS THIS VOLUME OF SOUND CONTINUES THE ENTIRE NIGHT AND IS QUITE DISTURBING AND MAKES SLEEPING IMPOSSIBLE IS THIS ISSUE ADDRESSED?
[End FF1]

FF. DANNY VAN ALLEN

FF1 Please see response to Comment Z1. See also pages 4.10-12 and 4.10-13 concerning noise impacts associated with the Contra Costa Power Plant. The same conclusions with respect to noise impacts were drawn for both the Pittsburg and the Contra Costa plants.

CPUC PUBLIC MEETING COMMENT SHEET

Name: Dolores Wright
Address: P.O. Box 1632
60 Edgewater Pl.
Pittsburg, CA
Telephone: 925-432-8831

[Begin GG1]
Comment: Has a baseline air quality study ever been studies in this area. If not, when. We are concerned about particulates in the air. The study should be made.
[End GG1]

[Begin GG2]
Why do we need 5 power plants in Pittsburg
[End GG2]

[Begin GG3]
How about the water adjacent to all these plants. What are the effects on Marine Life. Is the water ever treated.
[End GG3]

[Begin GG4]
Will the new owner be required to do these studies?

I think it is imperative that as a public entity you should have the new owner do this
[End GG4]

GG. DOLORES WRIGHT

GG1 Baseline conditions are described in the DEIR based on background concentration data from a Bay Area Air Quality Management District (BAAQMD) monitoring station in Pittsburg. Table 4.5-32 of the DEIR shows how maximum power plant concentrations compare to background concentrations and compares the combined result (i.e., power plant plus background) with the applicable ambient air quality standard. Table 4.5-32 indicates that maximum power plant concentrations together with maximum background concentrations of PM-10 do exceed the state 24-hour standard. However, the DEIR concluded that the increase in short-term PM-10 contribution from the plant is not significant (see page 4.5-64). Table 4.5-32 also indicates that maximum one-hour average nitrogen dioxide concentrations may exceed the corresponding standard, but those estimates have been revised for the Final EIR, and potential violations of that standard are no longer predicted to occur even under worst-case conditions (see response to Comment B11).

GG2 This comment does not pertain to the adequacy of the DEIR or to any potential environmental effects that would result from implementation of the proposed project. With respect to the potential combined impacts of the project together with known proposed power plants in the vicinity, please see responses to Comments B15 and R11.

GG3 The effects on the marine life from the intake and discharge of cooling water from the plants have been evaluated in several studies (see Section 4.7.3). These studies have led to a Resource Management Plan to operate the Pittsburg and Contra Costa plants in ways that minimize losses of fish; the redesign of the plants' cooling water intake systems to implement Best Technology Available; and a determination that the elevated temperature of the discharged water was not adversely affecting the abundance or diversity of aquatic species. The local Regional Water Quality Control Boards have placed limits on the quality of the effluent that can be discharged, and these limits would not change with the sale of the plants.

A number of chemicals are used throughout the plants for such purposes as cleaning and lubricating machinery. The wastes from these activities may be treated at on-site treatment plants and discharged with the cooling water or discharged to the sewer. These discharges are regulated by the Regional Water Quality Control Boards or the pertinent cities.

GG4 The regulations of the Regional Water Quality Control Boards would apply to the new owner(s) in the same way that they now apply to PG&E. The divestiture of these power plants will not change requirements related to water quality and the protection of aquatic plants and animals. Please refer also to response to Comment GG3.

CPUC PUBLIC MEETING COMMENT SHEET

Name: Bill Reed
Address: Box 205
Cobb, Cal. 95426
Telephone: (707) 928-5036

[Begin HH1]
Comment: It seems to me that the subject of seismic activity (in general) has not been properly addressed nor accurately portrayed of any time during development and operation of the Lake County Sonoma County development. I see this point as being again "glossed over" as a "minor" negative effect that in the total picture is not of significant impact. If this problem is not realistically dealt with now (as an item of the revue for sale of the existing plant) then when will it be addressed? I would like to see CPUC condition sale of this geothermal plant by a fuller (and more accurate) disclosure of seismic activity.
[End HH1]

HH. BILL REED

HH1 It could be argued that the issue of seismicity is addressed in the DEIR in greater detail than is warranted. There are numerous provisions in the California Environmental Quality Act (CEQA) that limit the amount of detail presented in an EIR (see, for example, Sections 15126[a], 15141, 15143, 15146, and 15147 of the CEQA Guidelines). In general, the information and analysis presented in an EIR should focus on the significant effects on the environment that would occur if the proposed project were implemented, and the depth of discussion should be in proportion to the severity and probability of occurrence of such effects. Effects that can be determined to be clearly insignificant and unlikely to occur can be dismissed from any extensive discussion in the EIR. In the case of seismic effects of the proposed project in the Geysers geothermal area, as noted in Section 4.3 of the DEIR, the proposed divestiture would not affect the ability to provide additional water to the Geysers steam fields, and therefore, the project would not alter the microseismicity effects in the area. Nonetheless, a detailed discussion of microseismicity in the area is provided in the discussion, and the results of earlier studies on the issue are summarized. The DEIR discussion acknowledges that water injection into the Geysers can result in increased microearthquakes. An Environmental Impact Report/Environmental Impact Statement (EIR/EIS) was prepared for the diversion of wastewater effluent from the Lake County Sanitation District's Southeast Regional Wastewater Treatment Plant to the Geysers and the injection of this effluent back into the steam fields to boost steam production. That EIR/EIS appropriately examined in detail the potential effects of that project on microseismicity in the area and concluded that the likely increase in microseismicity would not pose a public safety hazard or contribute significant to property damage, and would therefore be a less-than-significant impact. An EIR was also prepared for the proposed Santa Rosa Wastewater Modified Geysers Recharge Project, involving conveyance of up to 11 million gallons per day of wastewater from the City of Santa Rosa for injection in the Geysers steam fields. That EIR concluded that the wastewater injection project could result in an additional 140 annual microearthquakes. The proposed divestiture, however, would not have the potential to increase microseismicity or any other seismic impacts, and thus the level of detail presented in the DEIR on this issue is sufficient at the least.