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

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 ($\mu g/m^3$)							
					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	38 ~~132~~	358/396 ~~350.5/**483**~~	358/396 ~~350.5/**483**~~	262/300 ~~262/394~~	0	-96 ~~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	12.3/ND ~~12.3/12.3~~	15.9/ND ~~15.9/15.9~~	7.4/ND ~~7.4/7.4~~	3.6	-4.9
	annual	NA	15	ND	1.1/ND ~~1.1/1.1~~	2.2/ND ~~2.2/2.2~~	1.0/ND ~~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 simultaneous background concentration of nitrogen dioxide and ozone of 38 and 243 $\mu g/m^3$, 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.

> 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~~ <u>6.7</u> 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~~ <u>6.7</u> 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]

		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	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.