ATTACHMENT D

DIVESTITURE MODELING METHODOLOGIES AND ASSUMPTIONS

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1.0 INTRODUCTION

To support the economic and operational characterization of the operational and emission impacts of the proposed divestiture, the proprietary computer models SERASYM™ and the Surplus Energy Resource Assessment Model (SERAM II™)[1] were used to simulate the future operations of the California electric system and its interactions with the rest of the Western Systems Coordinating Council[2] after restructuring with and without the occurrence of divestiture of the fossil fired power plants as proposed by the San Diego Gas And Electric Company (SDG&E).

This attachment presents the case-specific sets of assumptions and modeling approaches on which the modeling analyses are predicated. In reading these sets of assumptions, the present system configuration with the ISO controlling the system should be assumed, with the listings below serving to call out especially significant continuations or interpretations of the status quo, indicate key assumed changes from present conditions, and/or delineate approaches and modifications to the modeling as appropriate for the scenarios under study.

2.0 NO-PROJECT CASES AND SENSITIVITY SCENARIOS

The "no-project" case postulating that the proposed divestiture project does not occur was modeled. The no-project case run for 1999 is the CEQA Baseline case (1999 Baseline case). The no-project modeling assumes the persistence of current utility generation ownership beyond the first phase of divestiture by the Pacific Gas and Electric Company (PG&E) involving the Moss Landing, Morro Bay and Oakland fossil fired power plants and the divestiture by the Southern California Edison Company (Edison) of all of its natural gas fired generation. The proposed Phase 2 divestiture of fossil and geothermal fueled power plants by PG&E is not assumed to have occurred or be effective. For consideration of divestiture effects and those of the alternatives identified, the No Project case was used as the starting point to produce further scenarios which incorporated additional assumptions and modeling stratagems to characterize operational and emissions impacts.

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1 SERASYM™ copyright © 1987-1995 Sierra Energy and Risk Assessment, Inc.: SERAM II™ copyright © 1989-1994 Sierra Energy and Risk Assessment, Inc.

2 The WSCC comprises California; the Pacific northwest, Mountain and inland southwestern states extending as far as east as western Texas; the Mexican state of Baja California del Norte and the Canadian provinces of British Columbia and Alberta.

2.1 BASELINE

The 1999 Baseline case assumes that neither further divestiture nor market power manifestations occur. It provides a CEQA "no project" baseline which is to be used as the basis of comparison with all other cases and scenarios.

2.1.1 KEY COMMON ASSUMPTIONS WITH PHASE 1 DIVESTITURE MODELING

A myriad of assumptions and modeling methodologies go into every model forecast of electric system operations. For the 1999 Baseline case, the same set of methods and assumptions were used, except as described below, as those employed in the baseline forecast reported in the Initial Study/Mitigated Negative Declaration for the Edison Auction and PG&E's first power plant auction in 1997 (Phase 1).[3] The assumptions from the first set of sales of particular importance to the proposed SDG&E sale include the following:

- Units continue to be bid into the ISO at minimum incremental cost and are dispatched per ISO/PX determination of minimum cost operations consistent with maintenance of system reliability.
- The ISO continues to hold agreements with its current list of "reliability must-run" (RMR) plants throughout the state, including all SDG&E plants proposed for divestiture, in the interest of having generation, and other ancillary services such as voltage support, from units at these plants available to maintain the reliable operation of the state electric system.
- The ISO operated system is assumed to include all of the interconnected northern California Municipal Utilities and the Los Angeles Department of Water and Power.
- The state's (and the WSCC region's) transmission systems see no major changes or upgrades other than those already approved and under construction.
- Average water conditions and resulting hydroelectric generation both in California and in the Pacific Northwest were assumed in all future years.

2.1.2 NEW ASSUMPTIONS FOR THE SDG&E DIVESTITURE SIMULATIONS

As the baseline case is intended to simulate present or near-present operations, the year 1999 was chosen for simulation as it will be the first full year of ISO operations of the California electric system. New and updated assumptions for the baseline case and the entire set of modeled scenarios where appropriate include those to follow. In all instances we assumed continuation of the existing terms and provisions of the contracts for power and energy for SDG&E, also known as the "intangibles" in some SDG&E divestiture filings. These contracts include SDG&E's ownership share of SONGS, its power purchase agreements with out-of-state utilities, and its standardized power purchase agreements with Qualifying Facilities.

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[3] Environmental Science Associates, *Mitigated Negative Declaration and Initial Study: Pacific Gas & Electric Company's Application No. 96-11-020, Proposal for Divestiture,* prepared for the California Public Utilities Commission, August 25, 1997, Attachment C, Section 2.

- California statewide electricity peak demand and annual sendout were updated to reflect the latest California Energy Commission (CEC) forecast.[4] Hourly load shapes for California utilities were updated to reflect the latest five years of Federal Energy Regulatory Commission (FERC) Form 715 data scaled to the CEC peak forecast.

- The new regional natural gas price forecasts just adopted by the CEC were employed, along with the corresponding updated inflation series forecast.[5] Special pricing adjustments were made for price of natural gas to SDG&E's generators to reflect final adjustments for the competitive transition charges on termination of interstate gas contracts into southern California. Low sulfur fuel oil price forecasts were adjusted relative to the natural gas price forecasts to be either "cheap" or "dear" depending upon the context of the scenario.

- Selected operating characteristics of the San Diego Gas & Electric and the PG&E fossil-fueled power plants proposed for divestiture, were updated to reflect current knowledge gained during visits to those plants.

- Heat rates and other generation characteristics were updated for all fossil plants pursuant to amended Reliability Must-Run Agreement (RMRA) schedules between the California Investor Owned Utilities (IOUs) and the ISO.[6]

- SDG&E's simultaneous import limit (SIL) from transmission to the north initiating at the San Onofre Nuclear Generating Station (SONGS) and from the east over the 500 kV Southwest Powerlink from Imperial County was assumed to be increased from 1,900 MW to 2,450 MW before 1999 thereby requiring less indigenous generation to serve SDG&E 's growing service area loads.

- Limitations to available natural gas for the fossil fueled plants due to gas pipeline transportation limitations are recognized and enforced on an average daily basis for each month. If all gas supplies are consumed during a given day then the individual boiler (i.e., steamer) units are modeled as being permitted to burn low sulfur fuel oil if needed for economics or to ensure electric system reliability.

- The ISO determined indigenous unit commitment rules as a function of peak daily load within the SDG&E service area as finalized in July 1998 are assumed to be followed in 1999 *et seq.*[7]

- Seventy megawatts of baseload generation from Edison's El Segundo plant were dispatched to satisfy an adjacent refinery's firm load.

- The special Mandalay natural gas supply contract between Edison and Southern California Gas Company was assumed to lapse, resulting in the Mandalay steam units receiving all natural gas at the same price as other Los Angeles Basin units.

- Pittsburg Power Plant Units 1 and 2 are operated to observe 115-kV voltage support requirements in PG&E's Delta Area during the summer peak period.

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4 California Energy Commission, *Staff Report: 1998 Base Energy Outlook*, July 1998, Report No. P300-98-012 (draft).

5 California Energy Commission, Fuel and Transportation Committee, *California Natural Gas End Use Prices Forecast in Support of the 1997 Fuels Report*, February 25, 1998.

6 PG&E, *Amendments to the Must-Run Agreement Between PG&E and the California ISO and Schedules for Must-Run Facilities*, filed at FERC, Docket No. -98-1614-0000, January 29, 1998. SDG&E Amendments to San Diego Gas & Electric Company's Master Must Run Agreements, March 1998.

7 ISO Operating Procedure, *Minimum Generation Commitment for San Diego*, June 30, 1998.

- Consistent with PG&E continued ownership of fossil plants, the BAAQMD “bubble” regulation of NO_x emissions and future downward ratcheting of NO_x emission limits under BAAQMD Regulation 9, Rule 11, and other current in-state air quality permit restrictions, continue to apply.

- Emission rates from combustion of fuel oil in the SDG&E units were taken from the *1994 Electricity Report* from the CEC.

- Various slight changes were made to the heat rates and capacities of the PG&E Delta and San Francisco plant units as identified in the PG&E Title V filing to the EPA.

- New default emission rates for carbon monoxide and condensable and filterable particulate matter less than 10 microns in diameter from natural gas fired boilers and combustion turbines are incorporated.[8,9]

- PG&E’s San Francisco Operating Criteria (SFOC) are adopted by the ISO and continue to be observed during all hours of the year. No additional transmission enhancements serving San Francisco, other than those enhancements recently being completed by PG&E, are assumed or reflected in reductions to the amount of generation operated in San Francisco needed to comply with the SFOC. The included enhancements were assumed to elevate import limits and shift SFOC requirements by 50 MW.

- San Francisco current and future loads were updated based upon a simple log-normal extrapolation of actual growth in peak loads from 1991 to 1997. The load shape and load factor was assumed to be identical to those observed in 1997. These hourly loads were “netted” out of the total forecasted PG&E service area loads as derived from the CEC forecast.

- PG&E Geysers units were assumed to have the contractual authority and technical ability to be economically dispatched. Unit-specific Geysers peak dependable generation decline rate forecasts, and capacity increases resulting from the new Lake County wastewater pipeline and supplying water for injection into Geysers steam fields (the Lake County Geysers Effluent Pipeline and Effluent Injection Project), were implemented.

2.1.3 ENHANCED MODELING METHODS AND APPROACHES

New requirements and questions became important in the process of performing the modeling for this phase of the divestiture. This necessitated applications of different and/or extended methodologies:

- A combination of Monte Carlo (MC) and probabilistic (i.e., cumulance) solution methods were employed in SERASYM™ to provide optimal results.[10] MC solutions with attendant long computer time simulations were used to more accurately predict secondary fuel burn and combustion turbine usage in San Diego while more expedient probabilistic simulations were used for other studies and for initial calculations.

8 U.S. Environmental Protection Agency, AP-42 , Supplement D, March 1998 & May 1998.
9 U.S. Environmental Protection Agency, AP-42 , Chapter 1-3, September 1998.
10 Monte Carlo methods utilized variance convergence techniques to minimize needed sampling.

- The nomogram describing the SIL for San Diego as a function of imports from Baja California was implemented in the model to insure precise limitations to imports and better modeling of indigenous generation requirements.

- The limited fuel usage modeling algorithm in SERASYM™ was further refined to permit precise modeling of the simultaneous usage of a common pool of limited natural gas for all the gas fired utility electric generation in San Diego. A shadow pricing approach was employed that optimized lowest cost generation from all the units prior to considering use of the secondary fuel (*i.e.*, fuel oil) which was assumed to be available in unlimited quantities.

- The Bay Area Reliability Requirements (BARR) for unit commitment were installed and observed in the modeling pursuant to the assumed adoption and enforcement of these operational requirements by the ISO.

- The operations of the Delta plants (Pittsburg and Contra Costa Power Plants) were refined to more accurately reflect how PG&E operates the individual units to satisfy the existing water quality permit (NPDES) and expected further endangered anadromous fish protection requirements for the period from February through mid-July period.

- Transmission modeling representations among utility members of the ISO were refined and enforcement of line rating limits enhanced.

2.1.4 BASELINE CASE RESULTS

The tabulated results for the 1999 Baseline case are presented in Table D.1, which exemplifies the standard presentation form used in this Attachment to present modeling results. Unit- and plant-specific results are presented for each of the fossil units proposed for divestiture. The table shows, for instance, that the unit with the highest expected capacity factor (given normal hydro conditions and the load and fuel price forecasts included) of the fossil steamer units proposed for divestiture is the 145 MW South Bay 1 with generation of 445 GWh while the largest total production comes from the 329 MW Encina 5 unit. At a capacity factor of 35 percent, South Bay 1 is operated mostly in support of the native generation requirements within the SDG&E service area.

Notice the column for generation by “2nd fuel”. This column reports on this usage. In this instance, SDG&E can use low sulfur residual fuel oil if economically warranted. A total of 14.3 GWh hours are projected for 1999 with South Bay 2 seeing the brunt of the burn. In all instances we assumed that the fuel oil had no more than about 0.35 percent sulfur, which is consistent with what is now found in the SDG&E oil tanks.

Air emissions for each of five pollutants are reported both in pounds per MWh and pounds per million Btu. For fossil-fueled plants, emissions of nitrogen oxides (NO_x), sulfur oxides (SO_x), carbon monoxide (CO), respirable particulate matter (PM-10) and reactive organic gases (ROG) are reported; for example, Encina 5 is shown with total 1999 NO_x emissions of 200 tons (51 pounds per billion BTUs) including emissions from the nearly negligible oil burn of 1 GWh. Similar information is provided for the four other pollutants for this unit and similar information is shown for the other SDG&E fossil steamers as well. The same type of information is provided for the combustion turbines except that there is no secondary fuel burn permitted. As can be seen on Table D.1, three of the CTs (South Bay, Division and North Island 1) only burn petroleum. Since SO_x is strictly a fuel-based pollutant, it is clear from looking at the emission rates that even the quite modest secondary oil burn is the major source of SO_x for the steamers. The petroleum burning CTs also have higher SO_x emission rates but they are all quite modest when compared to the sulfur emission from low sulfur, residual oil.

2.2 2005 SIMULATIONS

The year 2005 was chosen to ensure capture of all effects of the existing air quality regulations for the San Diego AQMD yet be sufficiently within the restructured period.

2.2.1 2005: NEW ASSUMPTIONS

- SDG&E's simultaneous import limit (SIL) from transmission to the north initiating at the San Onofre Nuclear Generating Station (SONGS) and from the east over the 500 kV Southwest Powerlink from Imperial County was assumed to be increased from 2,450 MW before 1999 to 2,850 MW by 2005 due to planned transmission enhancements within the SDG&E service area. This increase in import capability permitted less indigenous generation to be used to serve SDG&E service area loads. In fact, it permitted the existing generation system even with the expiration of the New Mexico 100 MW purchase to satisfy the level of indigenous generation needed for reliability considerations so that no new generation was added except as noted below.

- It is assumed that were SDG&E to continue ownership of the fossil plants, it would continue with its recently updated plan for installation of emission control devices on the steamers in order to satisfy the annual 650 ton NO_x ceiling currently scheduled to be in effect in San Diego prior to 2005. These further NO_x control enhancements consist of: installation of SCRs in South Bay units 2 and 3, installation of selective, non-catalytic reduction control units on Encina Units 1 through 3, and installation of low NO_x burners in Encina Units 4 and 5 to supplement the existing flue gas recirculation systems currently in place on those units.

- If the SDG&E plants are sold then it is assumed that the new owners would have to comply with the current requirements that after two years of ownership all boiler units would have to comply with more stringent NO_x emission rate requirements consisting of 0.15 lb. of NO_x/MWh and 0.40 lb./MWh for natural gas firing and residual fuel oil firing respectively. Further, upon sale it is also assumed that the new owners would not be able to use oil as readily in its boilers and that the use of oil would be limited to circumstances of *force majeure* that exhausted all available natural gas supplies.

- Resource modifications were made to areas not local to the plants being divested. Existing Los Angeles-area generation at High Grove and San Bernardino was repowered, and new generation added near the California border in Boulder City Nevada, consistent with CEC siting proceedings, Mojave Desert Air Quality Management District permit filings, and the best professional judgment of the Initial Study team. Additionally, new generation was added in San Diego to satisfy a capacity shortage caused by expected regional transmission import constraints and demand growth in San Diego County.

- Units 2 and 3 of the Hunters Point plant in San Francisco are assumed to be retired.

- No new transmission enhancements for delivery of power to San Francisco beyond those in operation by 1999 are assumed to be in existence.

- To meet load and reliability requirements in the face of local load growth, native power generation in San Francisco is supplemented by the construction of a 480-MW natural gas-fired resource patterned after the CPUC's "Identified Deferrable Resource" (IDR) with selective catalytic reduction,[11] thereby continuing to satisfy the SFOC while obeying emission limits.

- Pittsburg Units 3 and 4 are retired consistent with an emission control plan evaluated by PG&E and with an emission control case evaluated in PG&E's PEA for this proposed divestiture.[12] Units 1 and 2, slated for shutdown under the same plan, were retained to provide needed local system support including voltage support via their connection to the local 115-kV transmission system.[13]

- 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;[14] however, Pittsburg 1 and 2 were assumed retained for voltage support, with selective catalytic reduction (SCR) added to Pittsburg 2 to permit observance of the Bay Area air quality bubble standards in 2005.

2.2.2 2005 NO-PROJECT CASE

No simulations were made that postulated the continued ownership by SDG&E of the power plants because environmental impact comparisons of divestiture are being made with the 1999 Baseline case and because, unlike the Edison and PG&E divestitures where either utility was under no requirement to divest and either could have employed its auction simply to price the plants for retention, SDG&E is under an affirmative obligation to sell the facilities pursuant to the ruling by the CPUC authorizing the merger of Pacific Enterprises and ENOVA.

2.3 ANALYTICAL MAXIMUM GENERATION

2.3.1 PROCEDURES FOR RUNNING ANALYTICAL MAXIMUM GENERATION CASES

The analytical maximum generation cases are intended to study the potential impacts of selling the plants to private parties with incentives greater than those of SDG&E to maximize generation

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[11] Beginning in 1989 the CPUC's Biennial Resource Plan Update or BRPU (Investigation No. 89-07-004) formulated a process through which state utilities would obtain new generation to meet forecast resource needs by means of an auction. An alternate "default" new resource, the Identified Deferred Resource (IDR), was defined, representing the most cost-effective new resource the utilities would be expected to construct themselves, which "competed" with private bidders to build the generation and provided a cost comparison. The IDR was defined as a natural gas fired combined cycle plant with twin 240-MW units and the latest emission control technologies. The IDR resource is hereafter referred to as the new "480-MW station" or "two 240-MW units" in San Francisco.

[12] PG&E, *Proponent's Environmental Assessment: Pacific Gas & Electric Company's Proposed Sale of Four Bay Area Electric Generating Plants*, before the Public Utilities Commission of the State of California, January 14, 1998 ["Fossil Plant PEA"], pp. 5-13 to 5-21.

[13] Units 1 and 2 are the only Pittsburg units connected to the 115-kV system.

[14] PG&E, *Proposed Sale of Four Bay Area Electric Generating Plants, Op. Cit.*, Appendix B, page B-20.

sales from the plants they own.[15] Reasons a new owner might have incentive to run its units more than SDG&E are comprehensively discussed in Attachment C.

In order to investigate these potential effects, both the 1999 Baseline case and 2005 configuration of the electric system were used as starting points for a series of three sensitivity scenarios to test the environmental impacts of running these plants at their maximum credible levels of generation consistent with the market into which they sell. This market features some unavoidable limits that absolutely preclude *all* of these plants from simultaneously running full out. These constraints include the availability of the individual units; electric transmission limits; gas pipeline and other gas transportation limits that restrict total gas that may be made available to the plants; limited hourly demand net of ISO obligated must-run and must-take generation; existing take-or-pay contracts with out-of-state utilities; and competition from negligible or very low variable cost of generation sources including California hydro, lower cost coal generation and imports.

To implement these scenarios we chose to reduce their fuel costs in order to preserve relative economic dispatch order between the units. In the "analytical maximum" cases for the fossil plants, the natural gas prices seen by the natural gas-fired boiler units were replaced with the cheapest natural gas supply utilized in the Baseline case modeling, that of the plants with the lowest priced gas supply in California (the Coolwater plant in southern California), reduced by a further twenty-five percent and provided in quantities possible considering the limitations and higher priority customers for gas supplies imported into San Diego County.

This "analytical maximum" concept was also applied to the gas fired combustion turbines to be divested as well as with the resource addition in a 2005 scenario. The gas fired CTs were included in the Analytical Maximum even though it was anticipated that they would remain subject to Must-Run agreements with the ISO and would be committed only by the ISO. By offering cheaper fuel prices the new Owner would encourage the ISO to commit these units for reliability/ancillary purposes more frequently than other CTs in the state.

2.3.2 RESULTS FOR ANALYTICAL MAXIMUM GENERATION CASES

Each case features simultaneous Analytical Maximum operations of all the natural gas plants. These cases are quite similar to a case with a single owner purchasing all of the generation offered for sale, as happened in the first phase of the PG&E divestiture.

2.3.2.1 Analytical Maximum Generation - in 1999

Table D.2 shows the results for all the natural gas-fired steam boilers and CTs proposed for divestiture by SDG&E run at their analytical maxima consistent with available gas supply.

The use of the steamers increases tremendously with their overall capacity factor rising from 18.5 in the baseline case to 61.9 percent. If each plant had more gas supply their capacity factors would have risen even further since they could essentially run all the time and almost never

[15] *Cf.* Attachment C of this Initial Study.

produce more electricity than could be used within the San Diego service area. Interestingly, oil use for the steamers also increases substantially, rising from about 149 to about 8,205 billion Btus in which case it represents about nine percent of all generation.

CT use remains very low in spite of the much reduced price of natural gas. The usage does almost double but the increase is only from about 4 to about 8 GWh and would have essentially no environmental impact.

This case shows an increase of over 6,000 GWh of generation and, for example, a 4,265 ton increase in NO_X emissions. SO_X emission increases would be even more profound, relatively speaking, rising from less than 50 to over 1,500 tons annually. Such an increase in generation and emissions in 1999 would be permitted under the current San Diego Air Board rules which give a new owner a two year window (without a NO_X cap) within which to reconfigure units to meet the NO_X emission rate requirements of no more than 0.15 lb./MWh when burning gas and the ability to burn oil except on violation days within the San Diego airshed. Mitigation measures as otherwise discussed in this Initial Study would eliminate the potential for this worst case level of environmental impact.

2.3.2.2 Analytical Maximum Generation - in 2005 (Variant 1)

Table D.3 shows the results for the 2005 with all the natural gas-fired steam boilers and CTs proposed by SDG&E for divestiture run at their analytical maxima consistent with available gas supply. This case reflects the assumed mitigation measures imposed on the divestiture and implementation of the existing NO_X abatement requirements for new owners after two years of ownership. Oil was made so expensive that it would only be used in circumstances of great demand, essentially equivalent to a *force majeure* situation in which no gas would be available yet an important need for generation from units of these plants would be required by the ISO. Compared to the 1999 Baseline case, even though steamer generation almost doubles, the total level of NO_X emissions decline by about 50 percent. Other non-NO_X emissions tabulated do rise by, at least, a factor of two in response to the increase in generation and the reduction in natural gas supply with which to serve the steamers. The capacity factors of the CTs rise and total generation from CTs increases by about a factor of five. However, the amount of air emissions contributed by this generation is negligible for all pollutants except for NO_X. Since the steamers are all controlled with SCRs, the much higher rates of emissions from the CTs during operations and the sizable level of NO_X emissions contributed during startups are predicted to add nearly 100 tons to the total NO_X emission from the power plants. But, even with that increase and its inclusion of emissions of NO_X from startups, which are exempt from the cap, the annual cap figure of 650 tons is not violated.

2.3.2.3 Analytical Maximum Generation - in 2005 (Variant 2)

Table D.4 reports a 2005 Analytical Maximum case with new generation used to permit the retirement of the South Bay Power Plant. This scenario is meant to capture the likely worst case environmental effects of full implementation of the Letter of Understanding between SDG&E and the Port over sale of the South Bay plant. Key elements of this scenario are listed below:

- The new plant to be constructed to replace South Bay (i.e., referred to as IDR in the tables of results, or Otay Mesa) would have four 240 combined cycle units with an additional 100 MW CT for a total of 1,060 MW of generation. These efficient units would be equipped with SCRs that would limit emissions to no more than 0.15 lb. of NO_x per MW hour of generation.

- The new plant would have its own, dedicated firm gas supply and all of the gas that would otherwise have been available to both the South Bay and Encina plants would now be available to support Encina generation.[16]

- The new CT would be assumed to have a typical peaker-unit Must-Run agreement and would be used for reliability purposes solely.

- The new generation would eliminate the need for unit commitment of any units at the Encina plant with those responsibilities handed over to the newer, more efficient generation.

- The recommended mitigation measures for air emissions would still be implemented consisting of the need for SCRs and the restriction of use of fuel oil for generation. Relatively little fuel oil would be used under any circumstances since this scenario assumes much more gas is available to fire native generation.

As compared to the 1999 Baseline case, Variant 2 includes much greater generation and a bit more use of fuel oil by the steamers and the new plant. The new CT is used about twice as frequently as the existing CTs but even at that is used about a six percent capacity factor, well within the normal range of stand-alone CTs. Total NO_x emissions from generation is less in this scenario than in the 1999 Baseline case while other emissions increase somewhat.

3.0 RESULTS

From comparison of the results of the cases, the various scenarios, and the special analyses of alternatives, observations can be made that provide guidance in the divestiture environmental process. Observations evident from the results to date include:

- San Diego is an electrical island that must be supported by outside sources nearly all of the time and the magnitude of expected increases in the SIL is the key determinant of whether or not new generation will be required in San Diego apart from replacement of the existing South Bay plant were it to be retired.

- Overall emissions throughout the WSCC (including California) attributable to meeting California electric load decline substantially for NO_x, SO_x, and PM-10 and increase modestly for CO if the SDG&E plants to be divested are assumed to run at their full analytical maximum outputs consistent with available gas supplies.

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[16] The gas pipeline that supplies the South Bay plant currently runs right by the Encina plant.

- Modeling of analytical maximum operations of steam plants to be divested, based on existing physical and contractual limitations and intentionally optimistic natural gas supply price assumptions, results in increased operations of the plants by about 200 percent depending upon the year considered, which is still much less than a simple extrapolation of plant availability would conclude but would likely be much greater than the impact of a dry hydroelectric production season.

- The plants being divested that are not slated for retirement will increase their levels of production without divestiture in future years due to net growth in future statewide load after retirements and new plants are considered, so the maximum potential increase in generation associated with divestiture declines substantially between 1999 and 2005.

- The greatest potential increase in NO_x emissions due to divestiture, represented by the difference between baseline conditions and analytical maximum operations, declines very rapidly between 1999 and 2005 assuming future installation of emission control equipment on the plants consistent with current regulation.

- If the NO_x cap were transferred to the new owners for the two year period during which the stricter emission rate requirements were being retrofitted onto the steamers then the emissions rates for NO_x from the plants would likely decline more than if SDG&E continued to own the plants.

- The revised AP-42 standards just issued by the U.S. EPA substantially increase the predicted level of emissions from CO and PM-10 from the natural gas fired boilers.

insert table D.1- BSLMC.xls, tab 1999

insert table D.2 – AXLMC.xls, tab 1999

insert table D.3 – AXHMC0.xls, tab 2005

insert table D.4 – AXHC4.xls, tab 2005