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SOUTHERN CALIFORNIA EDISON

DRAFT CLOSURE PLAN

MANDALAY GENERATING STATION RETENTION BASIN SITE,

VENTURA COUNTY, CALFORNIA

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November 2007

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SOUTHERN CALIFORNIA EDISON

CLOSURE PLAN, MANDALAY GENERATING STATION RETENTION BASIN SITE, VENTURA COUNTY, CALIFORNIA

CLOSURE PLAN FOR THE WASTEWATER RETENTION BASIN SITE AT THE MANDALAY GENERATING STATION

November, 2007

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

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Cecil R. House, Senior Vice President

//original signed by//

Jack Sahl, Director, Environment, Health & Safety

//original signed by//

Randall S. Weidner, Project Manager

The undersigned certifies that all interpretative work conducted in support of this document was conducted in accordance with DTSC and EPA guidance.

//original signed by//

Dennis Jamison, CHG #471

The undersigned certifies that all investigative work conducted in support of this document was conducted in accordance with DTSC-approved work plans.

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Patrick Hamilton, CEG #998

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Any questions concerning the information or its interpretation should be directed to Dennis Jamison.

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INTRODUCTION

In 1995, Southern California Edison Company (SCE) signed an agreement with the Department of Toxic Substances Control (DTSC) to clean close the surface impoundments at eleven generating stations in Southern California. This was in accordance with the conditions set out in the Final Judgment and Stipulation Number 121219 handed down by the Superior Court of California, Los Angeles County, dated February 1, 1995. The Stipulation alleged that SCE had stored hazardous wastes in the surface impoundments without a permit. The Mandalay Generating Station is one of the facilities cited in the agreement. This station contains three wastewater retention basins or waste management units. These basins are presently lined with a high-density polyethylene (HDPE) liner to prevent leakage of wastewater from the basins.

This Closure Plan is organized into sections that cover facility and waste descriptions, site characterization activities, and plans and standards for site remediation. These sections are based on DTSC guidance for surface-impoundment closure plans (DTSC, 2006). The purpose of the Closure Plan is to allow DTSC and public review of the proposed plans, standards, and contingencies for remediating the retention basin site at the Mandalay Generating Station. Once the Closure Plan is approved, SCE will implement the plan, under the guidance and direction of DTSC. After the site is remediated, a Closure Certification Report will be generated to document the remediation process and demonstrate that the standards set forth in this Closure Plan were achieved. The Closure Certification Report will be approved by DTSC before the site closure is considered complete.

1. FACILITY IDENTIFICATION

Site Name: Mandalay Generating Station (wastewater retention basin site)

EPA Identification Number: CAD000630913

Contact Person (Project Manager): Randall Weidner (626) 302-4033

Facility and Mailing Address: 393 N. Harbor Blvd.,

Oxnard, California, 93035

Facility Owner and Operator: Reliant Energy Mandalay Inc.

Nature of Business: Generation of Electricity

The Mandalay Generating Station (the station) is a 560 megawatt station. The station has the capability to discharge up to 255.3 million gallons per day of once-through cooling water from two steam electric units (four condenser halves) into the Pacific Ocean (Reliant, 2005). The source of the cooling water is the Edison Canal, which conveys seawater from Channel Islands Harbor in Oxnard, to the southeast of the station.

SCE sold the Mandalay Generating Station in 1998, but retained responsibility under the contract of sale for environmental liability associated with the past operation of the retention basins during the period of SCE's ownership. This liability resulted from the past practice of temporarily storing boiler chemical cleaning wastes in the retention basins during the late 1980's to early 1990's. SCE discontinued the practice of storing hazardous boiler chemical cleaning wastewater in the North and South retention basins during the late 1980's to early 1990's.

Note that SCE is closing the Hazardous Waste Management Unit (HWMU) but is not physically closing the retention basins, which are necessary for continued operation of the station. Thus, the basins will remain in operation after the HWMU is closed.

2. FACILITY LOCATION

The station is located on the California coast, approximately 3 miles northwest of the City of Oxnard in Ventura County (**Figure 1**).

2.1 CLIMATE AND SURFACE HYDROLOGY

The station is situated in Ventura County which has a Mediterranean-type climate with warm, dry summers and cool, wet winters. Precipitation occurs mainly from November through April. Ventura County flood control records for a station about a mile and a half north of the site indicate an average precipitation of fourteen inches. The minimum recorded rainfall was 6.2 inches in 1976 with a maximum measured volume of 32.6 inches in 1978. The site is located about a mile and a half south of the mouth of the Santa Clara River. The Flood Insurance Rate Maps for Ventura County shows the Mandalay site outside the 100-year flood boundary.

Three surface water bodies are present within one mile of the site: the Pacific Ocean, cooling water intake canal, and McGrath Lake (**Figure 1**). The Ocean lies about 600 feet west of the retention basins. The normal diurnal fluctuation ranges from -0.5 to 3 feet. Infrequent extreme tidal fluctuations range from -1.8 to 6.8 feet.

In 1957, Edison constructed a canal from Channel Islands Harbor to the site. This canal conveyed ocean water for cooling purposes. The canal is about 150 feet wide at the top of the banks. The side walls have a 25 percent slope with a canal depth of 15 feet. The average daily flow with the plant in operation is approximately 250 million gallons. Water level in the canal is controlled by the ocean tides. There is no history of flooding from the channel.

McGrath Lake is located about a half mile northwest of the Mandalay site. The lake occupies an elongate, north-south trending topographic low that trends obliquely to the coastline. At its largest dimensions, it is a half mile long, 500 feet wide, and a maximum of 16 feet deep. The lake size and level responds to the flow in the Santa Clara River and irrigation runoff. For the past few decades, local agricultural interests have apparently used the lake as a catch basin for irrigation runoff. A drainage ditch along the north edge of the lake conveys water to the lake. McGrath Lake is upgradient of the retention basin site.

2.2 HYDROGEOLOGY

The station is situated near the northwest margin of the Oxnard Plain groundwater basin. The plain is bounded by the Santa Monica Mountains, Transverse Range, and Pacific Ocean. The strata in the Oxnard Plain comprise several thousand feet of marine and continental sediments of Tertiary and Quaternary age which were deposited on a pre-Cretaceous basement of igneous and metamorphic rocks.

The retention basin site is directly underlain by the following sequence: Perched aquifer, clay aquitard, and Oxnard aquifer. Information from onsite foundation borings indicates that the Perched aquifer is

110 feet thick. The upper 80 feet consist of fine to medium sand with local interbeds of gravel, silt, and clays. The basal 30 feet of the aquifer is predominantly medium sand and gravel. The Perched aquifer rests on a 20 to 25-foot thick clay unit locally referred to as the "clay cap" aquitard. The clay unit separates the Perched aquifer from the Oxnard aquifer. The foundation borings penetrated the upper 30 feet of this aquifer and found it to be composed of medium sand.

The Ventura county Department of Water Resources has related that no water wells are screened in the Perched aquifer. However, the Los Angeles Regional Water Quality Control Board's Basin Plan indicates that the existing beneficial uses for the Oxnard Sub-basin are Municipal, Industrial, Process, and Agriculture (RWQCB, 2006).

2.3 SITE GEOLOGY

Site-specific lithologic data was gathered during the installation of the groundwater monitoring wells and the collection of soil samples from beneath and adjacent to the basins and pipelines. The lithologic information shows a simple beach depositional environment beneath the facility. This has been complicated by ground modification for the construction of the generating facility and retention basins. The locations of the monitoring wells are shown on **Figure 2** while the positions of the compliance soil borings are displayed on **Figure 3**. Background soil borings (**Figure 4**) are located at the north fence (36 borings) and south fence (15 borings) of the station property. The bore-hole logs for each well and soil boring logs are contained in the referenced reports (**Appendix D**).

The well logs, background borings, and borings located to the north and west of the basins are believed to display undisturbed lithologic conditions. These areas show a 1 to 7-foot layer of silty sand over typical beach sand. The silty sand layer thickens towards the south of the basins. The silty sand is tan to brown in color, predominantly medium grained, with increasing gravel content toward the south. This layer was absent along the pipeline alignment. Instead, a consistent 2 to 3-foot layer of brown, silty sand was encountered. This silty sand differed from the native silty sand in the greater gravel content and the higher density. It most likely represents ground modification to create a firm foundation for the generating facility. Construction debris (wood, nails, glass) was encountered in this layer at borings P1 and P7 (locations shown on **Figure 3**).

The native and modified silty sand is resting on native sand deposits over the investigated area. The sand is predominantly tan to brown in color with a medium grain texture. Interfingered layers of black and gray sand were encountered in numerous borings adjacent to and below the basins. The black layers occurred in various thicknesses from thin lenses causing streaks on the sample tube to over 3 feet in background boring MB2 (location shown on **Figure 4**). The separation and accumulation of heavier sand grains from accessory minerals is typically observed in a beach depositional environment. Some of the dark layers reacted to a magnet indicating the presence of either iron or magnetite minerals.

The soil boring logs show that the color of some of silty sand and sand encountered beneath the North and South basins had been altered. In numerous borings, the natural tan or brown color had been changed to red, orange, or orange-brown. It is believed that the color change was caused by the percolation of wastewater through the vadose zone sediments. The wastewater oxidizes the iron rich sediments creating the altered color. It should be noted that no discoloration was observed in the bore-hole cuttings from below the BCCB, outside the basin footprints, or along the pipelines.

3. FACILITY DESIGN

The Station contains three wastewater retention basins (the retention basins): the North and South Basins, and the Boiler Chemical Cleaning Basin (BCCB). The three retention basins and their associated pipelines and appurtenances (e.g., sumps) form the retention basin site (or HWMU) that is the subject of this closure plan. The retention basin site is shown on **Figures 2** and **3**. Non-hazardous wastewater stored in the retention basins is commingled with spent cooling water and is discharged to the Pacific Ocean under NPDES permit number CA0001180.

The three basins were installed in 1977. The North and BCCB basins are 6 feet deep while the South Basin is 8 feet in depth. They were originally constructed with a single asphaltic concrete liner. In the 1980's, a single layer of a synthetic liner (HDPE) was installed in the three basins using the existing asphalt liner as a base. The Boiler Chemical Cleaning Basin (BCCB) was retrofitted in late 1989 with a double liner of HDPE and a leachate collection system.

The North and South Retention Basins are currently used to collect and store non-hazardous wastewater and stormwater runoff from the facility. The wastewater, containing minor amounts of oil, grease, and suspended solids, is systematically discharged to the ocean under the provisions of an NPDES permit. Historically, these basins and the BCCB were used to temporarily hold (for less than 30 days) acidic cleaning solutions from the removal of corrosion and mineral deposits from the boiler tubes. These cleaning solutions were stored in the basins until removal and offsite treatment. This cleaning process is no longer used at the site. The BCCB has been out of service since 1986, and currently collects and evaporates rainwater, since it has no outlet. BCCB wastewater was never discharged directly to the ocean.

Each of the two generation units are serviced by a boiler wash system that drains the wastewater from both the boiler acid and fireside wash processes. The drain for Unit 1 enters a 10-inch diameter pipeline which trends to the west. The pipeline turns and traverses north along the units to the sump at the base of the South Basin (**Figure 3**). The 10-inch diameter feeder pipeline from the Unit 2 drain enters the pipeline along the route. Since the wastewater flows by gravity, the depth of the pipeline varies slightly from 5 feet at Unit 1 to 7 feet at the sump.

The pipeline drains into the wastewater sump. The dimension of the sump is 10 feet by 10 feet with a depth of 14 feet. The wastewater from this sump can be pumped to any of the three basins through a valve tree. It can be conveyed by a surface pipeline to the South Basin or through a 10-inch diameter buried pipeline to a valve box. Here, the wastewater can be directed to either the North or Boiler Chemical Cleaning basins. The pipeline to the BCCB is a surface pipeline. Wastewater conveyed to the North Basin travels through a short section of buried pipeline before the basin dike.

4. DESCRIPTION OF HAZARDOUS WASTE CONSTITUENTS

This section presents available information on boiler chemical cleaning waste that was used at the station, and the investigation methods used to detect this waste in environmental media at the retention basin site.

Constituents of Concern (COCs) are the waste constituents, reaction products, and hazardous constituents that are reasonably expected to be in or derived from waste contained in the regulated unit (California Code of Regulations, 22 CCR s 66264.93). In this case the regulated unit is the retention basin site. Inorganic COCs present at concentrations that are statistically elevated with respect to site-specific background levels become Constituents of Potential Concern (COPCs) and are carried forward into a health risk assessment (DTSC, 1997). In addition, detected volatile organic compounds (VOCs) become COPCs unless the regulated unit is not the source of VOC contamination or the percentage of detections is determined by DTSC to be statistically insignificant.

Accordingly, inorganic chemicals found in site investigation samples are termed “elevated” if they are determined through statistical analyses to be significantly higher than corresponding background levels. Chemicals that are detected at high concentrations are not necessarily elevated if their background concentrations are also detected at high levels. Chloride in coastal groundwater is an example of this situation. Summary statistics for soil, soil gas, and groundwater COC concentrations in site investigation samples are presented in **Tables 1** through **3**.

In the case of the Mandalay retention basin site SCE acknowledges (without presenting statistical analyses) its opinion that arsenic, nickel and vanadium are the most highly elevated chemicals found in soil and groundwater samples. This acknowledgement is to assist the reader in understanding the weight and probable conclusions that may be formed based on the site investigation data. (However, supporting statistical analyses for all inorganic COCs will be presented in the Closure Certification Report, to be issued following site remediation [as described in **Section 16**].) Chemicals such as aluminum, chloride, total chromium, iron, manganese and zinc were detected at high concentrations in soil and/or groundwater during the site investigation and may eventually be demonstrated through statistical analyses in the Closure Certification Report to be “elevated”. Thus other chemicals could potentially be identified as COPCs. Prior to DTSC approval of SCE’s application for site closure, all COPCs (elevated chemicals and VOCs) will have to meet the Closure Performance Standards described in **Sections 11** or **19**.

4.1 LIST OF COMPOUNDS

Refer to **Appendix A** for a representative analysis of boiler chemical cleaning waste. The chemicals generally associated with boiler chemical cleaning include the following: copper, nickel, vanadium, and zinc. Arsenic has been identified as being significantly elevated in soil beneath the retention basins, however, there is no available documentation that arsenic is a by-product of boiler chemical cleaning. The chemicals with the highest concentrations (greater than 1 mg/l) in **Appendix A** are: total chromium, copper, fluorine, lead, molybdenum, nickel, and zinc.

4.2 LIST OF TEST METHODS

Analytical test methods used to evaluate the compounds listed in **Appendix A** are shown in **Table 4** and discussed in **Section 9**. In summary, metals are analyzed in soil and groundwater samples collected at the retention basin site, while VOCs are analyzed in soil, soil gas, and groundwater samples.

4.3 LIST OF SIGNIFICANT HAZARDOUS WASTE CONSTITUENTS

Refer to **Appendix A** for a representative analysis of boiler chemical cleaning waste. A preliminary assessment of the key COCs in soil and groundwater indicates that arsenic, nickel and vanadium are the most highly elevated compounds found in soil and groundwater samples.

4.4 BACKGROUND AND SITE INVESTIGATION

Field investigations were performed within and around the retention basin site to characterize soil, soil gas, and groundwater in the area where historical boiler chemical cleaning operations may have led to contamination. For purposes of this Closure Plan, this potential area of contamination will be defined as the "exposure area", which includes the basin, pipeline, and associated down gradient area (**Figure 3**).

Soil gas samples from 37 probe locations in the exposure area were collected in November 2004 and analyzed for VOCs, using Method 8260B, in an on-site mobile laboratory operated by American Analytics (Komex, 2005a). No VOCs were detected (**Table 2a**). For purposes of confirmation, Summa canister samples were collected at six of the 37 locations and analyzed for VOCs, using Method TO-14A, in a fixed laboratory operated by Severn Trent Laboratories, in Santa Ana, California. (Thus a total of 43 soil gas samples were collected from 37 probe locations.) Using Method TO-14A, five VOCs were detected at very low levels (less than 0.2 ug/l) in the Summa canister samples (as shown in **Table 2b**).

The TO-14A analyses were designed to confirm the results of the 37 analyses performed with Method 8260B. As shown in **Tables 2a** and **2b**, Method TO-14A has detection limits 70 to 200 times lower than for Method 8260B. No chemicals were detected by Method TO-14A at levels above the corresponding detection limit for Method 8260B, thus the results are internally consistent.

In addition, all detections of chemicals in soil gas were at concentrations below their respective California Human Health Screening Levels (CHHSLs) (California Environmental Protection Agency, 2005). This finding is not a substitute for a soil gas risk assessment, which will be performed as described in **Section 11**. However, the finding of no CHHSL exceedances indicates that risk levels associated with the detected soil gas concentrations are relatively low.

Of the chemicals detected in soil gas using method TO-14A, only xylene was detected (in one sample, SG-1) near a monitoring well (MW-19) where it had been detected in the past. Xylenes were about 4 orders of magnitude lower in soil gas sample SG-1 than their respective CHHSL. Otherwise, the constituents detected in the Summa canisters do not correlate to other VOC data from groundwater (**Table 3**) at the site.

Two hundred fifty soil samples from 73 borings in the exposure area were collected during the period of August 1997 through January 2006 (Hamilton, 2006). A list of COCs that were detected by this characterization program is presented in **Table 1**. No VOCs were detected in any of the 108 soil samples collected beneath the basin liners through November 2003. As noted above, no VOCs were detected in the 37 soil gas samples analyzed using Method 8260B (**Table 2a**).

Since no VOCs were detected by Method 8260B in either soil or soil gas, VOC analyses for soil samples collected at the retention basin site were discontinued, with DTSC concurrence, beginning in March 2005.

Four hundred ninety-four groundwater samples from 28 monitoring wells in the exposure area were collected during the period of September 2001 through June 2006 (Hamilton, 2007). Prior to September 2001, an additional 165 groundwater samples were collected from the monitoring wells in the exposure area, however, analytical detection limits in use during this period were generally higher. A list of COCs that were detected during the period of September 2001 through June 2006 (when detection limits were lowest) is presented in **Table 3**.

5. ESTIMATE AND MANAGEMENT OF MAXIMUM INVENTORY

No hazardous waste was stored in the retention basins and appurtenances during the period of characterization (1996 to 2006). The current owner/operator does not have a permit to store hazardous waste in the retention basins. Non-hazardous wastewater is stored and released under the previously noted NPDES permit.

SCE discontinued the practice of storing hazardous waste in the retention basins approximately 6 to 10 years prior to the sale of the station (in 1998), and to the best of our knowledge the current owner has continued the established practice of using the retention basins only for non-hazardous waste.

The maximum potential historical inventory (i.e., the maximum potential inventory before 1996) is equal to the combined volume of the three basins. The capacities of the North Basin, South Basin, and BCCB are estimated to be 0.51 million gallons (MG), 0.56 MG, and 0.43 MG, respectively. The combined capacity is 1.50 MG, representing the estimated maximum potential inventory that would exist if all three basins were filled with hazardous wastewater at the same time. It is unlikely this situation ever occurred, since the BCCB was used intermittently, and operational safety policy has been to keep the basins below fifty percent of capacity. However, the value of 1.5 MG is useful as a theoretical upper limit on the historical inventory of hazardous wastewater stored at the retention basin site.

6. DECONTAMINATION PROCEDURES FOR EQUIPMENT, STRUCTURES, AND BUILDINGS

The retention basins are emptied and cleaned as a routine operational procedure, to remove wind-blown sand and stormwater sediments. These materials are removed by the station operator to maintain full retention basin storage volume. SCE considers it unlikely that any residual contamination is present in the basin sediments, since the basins have not stored hazardous wastewater for up to twenty years (**Section 3**). However, it is SCE's opinion that the annual cleaning process described below would effectively remove residual contamination if it were present in the basin sediments. Details of this process are given below.

The retention basins are cleaned approximately once per year or as needed, by the current owner (Reliant Energy). The cleaning procedure is to maintain one basin in service while the opposite basin (e.g., North or South) is drained and allowed to dry out. The sediments are then swept up and placed into a 20 yard roll off container. Once a basin is cleaned, it is put back into service and the same process is repeated for the opposite basin. This process usually takes approximately 30 days to complete.

After the cleaning is completed, samples of the sediments are sent to a certified laboratory for standardized analysis, to determine whether or not they exhibit any hazardous characteristics, as defined in Title 22 of the California Code of Regulations (CCR). These characteristics include ignitability, reactivity, corrosivity, and toxicity. When the analysis establishes the material to be non-hazardous, it is shipped off site to a waste receiving facility licensed to receive such waste.

SCE has obtained documentation from the current owner on dates of sediment removal in the last two years: June to July 2006 and July to August 2007. The boiler chemical cleaning basin, which stores only rainwater, was last cleaned in approximately 2001.

Sediments removed from the basins (including the South Basin, where the highest concentrations of metals were found in the underlying soil) were sampled and submitted for waste characterization analysis on August 23, 2006 and August 27, 2007. The sediments were determined to be non-hazardous in 2006, and the results from 2007 are pending (CleanHarbors, 2006) (reference contained in **Appendix D** of the Closure Plan).

Decontamination of the basin liners is not considered necessary. Comprehensive leachability testing of similar liner material from the former SCE Long Beach Generating Station (Komex, 2005b) indicated there were no leachable contaminants within the liner samples that represented a health risk to ecological or human receptors.

Water has continuously flowed through the pipelines leading to the retention basins, due to normal operation of the generating station over the period of approximately 14 to 18 years since hazardous wastes were last stored in the basins. Due to the operational flow, there should be no sediments from this period remaining in the pipelines.

There are two sumps connected to the pipelines and basins that potentially could contain residual sediments from the period when hazardous wastes were stored in the basins. Decontamination procedures will include: inspection, solids removal, pressure washing, and testing (confirmation sampling) of the wash water and solids. Based on the list of COCs established for this site, confirmation samples will be tested for metals and VOCs. Decontamination wash water and solids will be removed and properly disposed, based on the results of the analytical testing.

7. CONFIRMATION SAMPLING PLAN FOR CONTAINMENT STRUCTURES, TANKS, AND EQUIPMENT

SCE believes that confirmation sampling at the retention basin site applies only to the sumps, since the basins and pipelines no longer contain sediments from the time period when the site facilities were used for storing hazardous waste. Details on the cleaning of facilities at the retention basin site are given in **Section 6** above.

Confirmation sampling will be performed in the sumps, by testing the wash water after the sumps are cleaned. If solids are collected during the confirmation sampling, they will be sampled along with the wash water. The wash water and any solids will be analyzed as described in Section 6, in consultation with DTSC. The methods listed in **Table 4** will be used, as appropriate.

8. SOIL SAMPLING PLAN

Soil and soil gas investigations have been performed at the site by SCE, and SCE believes the soil at the retention basin site has been fully characterized. The resulting characterization reports have been reviewed by DTSC. SCE has concluded that the soil and soil gas characterizations are complete and are sufficient to allow SCE to proceed with site remediation and closure. The sampling plans, methods, and analytical results are presented in the Soil Characterization Report (Hamilton, 2006), referenced in **Appendix D** of the Closure Plan. The confirmation soil sampling plan is described in **Section 12.1**.

SCE's grid of soil borings was extended outward from the retention basin site until a significant attenuation in contaminant concentration (approaching background levels) was observed. Background concentrations for metals in soil are presented in **Table 1**. No VOCs were found in soils at the site. At the outermost soil sample locations, concentrations of the key metals associated with boiler chemical cleaning (nickel and vanadium) were attenuated to within the maximum background concentrations. Arsenic was also attenuated to within the maximum background concentrations.

SCE believes the soil gas at the retention basin site has been fully characterized. The sampling plans, methods, and analytical results are presented in the Soil Gas Survey Report (Komex, 2005a), referenced in **Appendix D** of the Closure Plan. No VOCs were detected in the 37 soil gas samples analyzed using Method 8260B (**Table 2a**). Using Method TO-14A, five VOCs were detected at very low levels (less than 0.2 ug/l) in the six Summa canister samples (**Table 2b**). Further details are given in **Section 4.4**. As shown in **Tables 2a** and **2b**, Method TO-14A has lower detection limits than Method 8260B. Since no VOCs were detected by Method 8260B in either soil or soil gas, VOC analyses for soil samples collected at the retention basin site were discontinued, with DTSC concurrence, beginning in March 2005.

9. ANALYTICAL TEST METHODS

Analytical test methods used for soil, soil gas, and groundwater samples collected during the field investigations (**Section 4**) are summarized in **Table 4**. The analytical work for soil and groundwater samples was performed by Weck Laboratories, Inc, an Environmental Laboratory Accreditation Program (ELAP) certified lab. Soil gas samples were analyzed by American Analytics and Severn Trent Laboratories, which are also ELAP certified.

Soil samples collected at the retention basin site were analyzed for metals using the United States Environmental Protection Agency (USEPA) methods shown in **Table 4** (Hamilton, 2006). Soil samples were analyzed for VOCs using USEPA Method 8260B.

Soil gas samples collected at the retention basin site were analyzed for VOCs using USEPA Method 8260B (Komex, 2005a). Additionally, Summa canister samples were collected at six of the 37 soil gas probe locations and were analyzed for VOCs using USEPA Method TO-14A (Komex, 2005a).

Groundwater samples collected at the retention basin site were analyzed for metals using the USEPA methods shown in **Table 4** (Hamilton, 2007). Groundwater samples were analyzed for VOCs using USEPA Method 8260B.

10. GROUNDWATER SAMPLING

The station is located in the Santa Clara River Valley Groundwater Basin and the Oxnard Sub-basin. The Los Angeles Regional Water Quality Control Board's Basin Plan indicates that the existing beneficial uses for the Oxnard Sub-basin are Municipal, Industrial, Process, and Agriculture (RWQCB, 2006).

SCE believes the groundwater at the retention basin site has been fully characterized. The sampling plans, methods, and analytical results are presented in the Water Quality Monitoring Program and Sampling and Analysis Plan (Hamilton, 1996 and 2000), and the most recent Annual Groundwater Monitoring report (Hamilton, 2007). Both documents are referenced in **Appendix D** of this Closure Plan. The monitoring well network was extended outward from the retention basin site until a significant attenuation in contaminant concentrations (approaching background levels) was observed. Background concentrations for groundwater are presented in **Table 3**.

Groundwater sampling data considered for site closure evaluations were collected quarterly during December 1996 through June 2006. However, analytical detections limits decreased during this period. Recent data have lower detection limits and are more relevant to assessing current conditions.

To select an appropriate time period for groundwater data evaluation, groundwater samples collected during the last five years (2001 to 2006) will be used for the evaluations described in this Closure Plan.

All monitoring wells included in the sampling program, except the background well (MW-6), are within the exposure area for risk assessment purposes.

The current status is that groundwater monitoring investigations have been performed at the site by SCE at the monitoring well locations shown on **Figure 2**. Table 1 of the Annual Groundwater Monitoring Report (Hamilton, 2007) describes construction details for the monitoring wells. Four hundred ninety-four groundwater samples from 28 monitoring wells in the exposure area were collected during the period of September 2001 through June 2006 (Hamilton, 2007). The resulting characterization reports have been reviewed by DTSC. SCE has concluded that the monitoring well network is complete and the data collected are sufficient to allow SCE to proceed with site remediation and closure.

11. CLOSURE PERFORMANCE STANDARDS (CLEANUP LEVELS)

SCE intends to close the retention basin site to meet clean closure (unrestricted land use standards) following site remediation (**Section 12** and **Appendix B**). Clean closure can be achieved in accordance with Closure Performance Standards either by: 1) Demonstrating that no COPCs are identified at the retention basin site through site characterization and statistical analysis, or 2) Demonstrating that COPCs identified at the retention basin site were remediated to concentrations that are below background or risk-based criteria. Background concentrations for metals and groundwater are presented in **Tables 1** and **3**, respectively. The distinction between the terms “COC” and “COPC” is explained in **Section 4**.

Figure 5 is a Conceptual Site Model (CSM) that illustrates the potential exposure routes from the points of chemical release at the retention basin site to human and ecological receptors. Under current (2007) land use conditions, the potential human receptors are industrial workers and construction workers. Under future unrestricted land use conditions (i.e., after the generating station is decommissioned and removed), a resident is considered as a hypothetical human receptor in order to support closure. Potential exposure routes for aquatic and terrestrial ecological receptors under both current and future land use conditions were evaluated by DTSC’s toxicologist (HERD, 2007) based on a site walk. This evaluation confirmed that there are no pathways for either aquatic or terrestrial receptors at the retention basins.

The retention basins are currently lined and the remainder of the retention basin site is paved, hence, there are no potential direct exposures of the industrial workers through ingestion and dermal contact with COPCs in surface and subsurface soil. However, construction workers may potentially be exposed if construction activities include excavation within the site area. Similarly, indirect contact through inhalation of dust-borne particulates is also incomplete for industrial workers but not for construction workers. VOCs were detected in soil gas, thus, potential vapor emissions to ambient air is a potential transport route for both industrial workers and construction workers. The groundwater ingestion, dermal contact, and inhalation exposure routes are incomplete for industrial workers. Construction workers are not exposed via groundwater ingestion but may potentially be exposed by dermal contact with groundwater and inhalation of vapors emitted directly from groundwater that may seep into an excavation. The latter exposure is indicated on **Figure 5** as volatilization from the groundwater secondary source to the outdoor/indoor air exposure point.

As described in **Section 3**, acidified wastewater was not discharged directly to the ocean. Thus, there is no likelihood that chemicals from the retention basins were released or transported to the ocean or surface water, and ultimately, to aquatic receptors. Therefore wastewater is not a secondary source on **Figure 5**.

Under future conditions, the site is assumed to have no basins or liners and the surface is assumed to be unpaved. A future resident is assumed hypothetically to come into contact with the surface and subsurface soil (assuming subsurface soils are disturbed and re-distributed at the surface), dust-borne particulates, soil gas, and groundwater (see **Figure 5**) through ingestion, dermal contact, and inhalation. A future industrial worker and construction worker are assumed hypothetically to be exposed through the same routes as a resident. However, the groundwater exposures for industrial and construction workers shown on **Figure 5** are limited to dermal contact for the future construction worker, based on the following rationale:

- Groundwater ingestion for residents poses a more restrictive constraint for assessing risk than groundwater ingestion for industrial and construction workers. This exposure route (i.e., for resident receptors) is included on **Figure 5**. Thus industrial and construction workers are not shown as receptors for the groundwater ingestion exposure route.
- Industrial workers are not exposed by dermal contact with groundwater.
- The groundwater inhalation route accounts for residential showering, which doesn't apply to industrial and construction workers, since they are assumed not to live on-site.
- Construction workers may be exposed to volatiles released directly to outdoor air should groundwater seep into an excavation (as discussed above).

Note that the cooling water canal is assumed to remain in place after closure of the retention basin site. Also, based on long-term monitoring of the groundwater, it is concluded that the plume is stable and COPCs will not migrate into the canal. Therefore, exposure routes to aquatic ecological receptors are deemed incomplete under future site conditions

Additional information will be collected during remediation. Accordingly, the CSM may be modified based on any determinations indicating that future (post-remediation) conditions differ from those depicted in **Figure 5**. If complete exposure routes are identified, closure performance standards may need to be met to achieve protection of ecological receptors and the environment.

The suite of COCs (see **Table 4**) analyzed and reported in the site characterization reports will be evaluated for site closure. Each COC can potentially become a COPC according to the DTSC criteria for identifying statistically elevated chemical concentrations.

The initial closure performance standards for metals in the soil and groundwater are the corresponding background levels. In the event that it is not technically feasible to remediate to background concentrations, the closure performance standards for the site soil will be health risk-based criteria for unrestricted closure. USEPA guidance indicates that a cumulative carcinogenic risk range between 1 in 1,000,000 and 1 in 10,000 and 1 in (1×10^{-6} and 1×10^{-4}) is considered to be protective of public health. The lower end of this risk range is typically applied to residential situations and is considered the point of departure by the U.S. EPA and DTSC. Accordingly, the human health risk-based criteria for carcinogens will be based on a target carcinogenic risk of 1×10^{-6} and the human health risk-based criteria for noncarcinogens will be based on a target hazard index of 1. Risk-based closure performance standards for metals in soil will be evaluated to ensure they are protective of groundwater and ambient water quality.

For groundwater, the closure performance standards will be the maximum contaminant levels (MCLs) for protection of human receptors and the water quality criteria, such as the most protective criteria protective of aquatic organisms in the California Toxics Rule or the California Ocean Plan for protection of ecological receptors.

A Closure Certification Report (**Section 16**) will be generated to demonstrate that the closure performance standards described in this section are met following remediation.

A Land-Use Covenant (LUC) and Implementation and Enforcement Plan (IEP) will be prepared and approved by DTSC, as described in **Section 19**, if clean closure can not be achieved.

12. SOIL AND GROUNDWATER REMOVAL/CLEANUP PROCEDURES

The overall remediation strategy will be to use SCE's characterization data, statistical analyses, and risk assessments to identify the specific contaminants and locations that require remediation to achieve the site's closure performance standards.

12.1 SOIL REMOVAL/CLEANUP PROCEDURES

A preliminary assessment of the key COCs in soil indicates that arsenic, nickel and vanadium are the most highly elevated compounds. The Closure Certification Report (**Section 16**) will provide a comprehensive assessment of the chemicals that require remediation.

It is anticipated that the contaminated soil beneath the retention basins will be excavated and removed as needed to meet the Closure Performance Standards. The excavations may extend as deep as the water table (estimated to be approximately 10 feet below the floor of the North Basin and 5 feet below the floor of the South Basin). The excavation process will include the use of engineered controls to stabilize the excavation and provide a safe work environment.

Confirmation soil samples will be collected from the walls and bottom of the excavation on approximate twenty foot centers. The samples will be analyzed for the COPCs identified through statistical and risk analysis of the characterization data, in consultation with DTSC. The methods listed in **Table 4** will be used, as appropriate.

If analyses of the confirmation samples show that the closure performance standards have not been met, then additional soil may be excavated laterally and to the water table. The confirmation sampling will be repeated as well.

The completed excavation will be backfilled with clean, compacted fill (for which confirmation samples will also be collected and analyzed). The basin liner will be repaired as necessary. The remediation equipment will be decontaminated by pressure washing. Decontamination wash water and residue will be characterized and removed for disposal at a permitted facility off-site as described in **Section 6**.

The excavated soil will be characterized in accordance with the CCR Title 22 as described in **Section 6**, and disposed of at an appropriate facility, based on a determination of whether or not it is hazardous. Investigation-derived waste will not be stored on-site for more than 90 days. Soil removal, transport, and cleanup procedures will conform to DTSC guidelines. A Remedial Implementation Plan will be prepared and approved by DTSC prior to initiation of cleanup.

12.2 GROUNDWATER REMOVAL/CLEANUP PROCEDURES

A preliminary assessment of the key COCs in groundwater indicates that arsenic, nickel and vanadium are the most highly elevated compounds. The Closure Certification Report (**Section 16**) will provide a comprehensive assessment of the chemicals that require remediation. It is anticipated that groundwater at the site will be remediated by in-situ treatment with appropriate treatment chemicals. In general, the procedures listed below will be followed.

Samples of soil below the water table and groundwater within the plume area will be collected and analyzed to design the groundwater treatment plan. The soil samples will be collected using a geoprobe. Protocols established in the existing sampling plans for the site will be followed. These samples will be collected in the area within the arsenic, nickel, and vanadium plumes as represented on the contour maps presented in the annual monitoring report (Hamilton 2006, Figures 10 through 12).

Laboratory testing of soil and groundwater samples will be performed as described in **Appendix B**, to select the optimum treatment chemicals and injection amounts for immobilizing the metals in the groundwater plume. SCE's goal is to evaluate and select treatment chemicals that would bond with the contaminant metals to limit their mobility through reduction, sorption or precipitation of less-soluble phases. As stated in **Appendix B**, preliminary analysis indicates that calcium polysulfide and zero-valent colloidal iron are promising alternatives.

The selected groundwater treatment chemical (probably calcium polysulfide or zero-valent colloidal iron) (**Appendix B**) may be added within the excavation area to accelerate the remediation of groundwater. The selected treatment chemicals will be injected in the area of groundwater contamination (exposure area) as described in **Appendix E** and in accordance with a DTSC-approved Remedial Implementation Plan. The remediation equipment will be decontaminated by pressure washing. Decontamination wash water and residue will be characterized and removed for disposal at a permitted facility off-site as described in **Section 6**.

On-going groundwater monitoring (**Section 15**) will serve as confirmation sampling to evaluate the efficacy of the treatment chemicals on meeting the site's Closure Performance Standards for groundwater. Groundwater samples will be collected and analyzed according to the existing Water Quality Monitoring Program and Sampling and Analysis Plan (Hamilton, 1996 and 2000).

12.3 CULTURAL AND BIOLOGICAL RESOURCES

Cultural Resources

Based on a record search completed by the SCE archaeologist at the South Central Coastal Information Center of the California Historical Resources Information System, no cultural resources are recorded on the Mandalay Generating Station site. To further ensure that such resources are not impacted, SCE will have an archeologist present during all earth moving activities, with appropriate 'project control measures' enacted. As part of proposed 'project control measures' for the site, if any potential cultural resources are encountered, all work must halt at that location until the resources can be properly evaluated by a qualified archaeologist. Further, if human remains are unearthed during excavation, State Health and Safety Code Section 7050.5 state that "…no further disturbance shall occur until the County Coroner has made the necessary findings as to origin and distribution pursuant to Public Resources Code Section 5097.98.

Biological Resources

A search of the California Natural Diversity Data Base (CNDDB) for the Oxnard USGS 7.5-minute quadrangle as well as a review of other literature regarding listed species indicated that a number of state and/or federally listed or otherwise sensitive species have the potential to occur in the general area of the proposed project. A search of the Department of Fish and Game's California Natural Diversity Database (rare find) search found sensitive species in the area of the sand dunes but not at the project site and none of the project activities will have any impact on these species and habitat. The planned work area is fenced from any potentially sensitive habitat areas (non paved areas).

13. CLOSURE COST ESTIMATE

A cost estimate for performing the anticipated remediation is described in **Appendix E**. The soil remediation cost was estimated using three scenarios. These include a situation where: 1) the excavated soil is characterized as non-hazardous and can be disposed at a local landfill, 2) the excavated soil is California-only hazardous, or 3) the excavated soil is RCRA-hazardous. The total estimated cost for soil remediation under these scenarios is $504,400, $726,400, and $937,600 respectively (**Table E-1**). The main cost differentials are related to transportation and disposal fees.

Costs were estimated for injection of treatment chemicals into aquifer zones contaminated by arsenic, nickel and vanadium. The treatment strategy assumed for the cost estimate is immobilization. The costs include aquifer media sampling and treatability testing, and implementation of an assumed remedial technology. The total estimated cost for groundwater remediation under these scenarios is $657,000 (**Table E-2**).

14. FINANCIAL RESPONSIBILITY

A statement of financial assurance is included in Appendix F.

15. CLOSURE IMPLEMENTATION SCHEDULE

The time frame for any remedial activities will be based on the approved closure plan date.

Post-remediation groundwater monitoring to track the effectiveness of the remedy will continue for a period of up to five years to assess progress toward meeting the Closure Performance Standards (**Section 11**).

Progress reports and /or continued quarterly groundwater monitoring reports will be submitted during that assessment period, as required by DTSC.

Details concerning the contingency plan that will be followed if the Closure Performance Standards can not be met within five years are presented below (**Section 19**).

If the remedy is found to be effective in meeting the standards within five years, groundwater monitoring to confirm clean conditions will continue for a period of three years after the groundwater concentrations reach acceptable levels. The groundwater monitoring network may be modified (streamlined) depending on the timeframe for certification of the remedy.

After SCE demonstrates that the Closure Performance Standards (**Section 11** or **19**) have been met, a Closure Certification Report will be prepared.

A schedule showing major milestones and corresponding dates to meet the above timeframe will be presented prior to initiating remediation field work. If necessary this schedule may be revised with prior approval from DTSC.

16. CLOSURE CERTIFICATION REPORT REQUIREMENTS

The Closure Certification Report will document the results of site characterization activities, statistical analyses to select Chemicals of Potential Concern, and risk assessments used to develop Closure Performance Standards for the site. In addition, the Closure Certification Report will document the treatability studies, remediation activities, evaluation of confirmation sampling, and present the necessary data and evaluation to support the conclusion that the site's Closure Performance Standards have been met for soil, soil gas, and groundwater. Note that the CSM (**Figure 5**) and list of COPCs will be re-evaluated to account for post-remediation data such as results of confirmation sampling.

17. PERSONAL PROTECTIVE EQUIPMENT (WORKER HEALTH AND SAFETY)

A health and safety plan (HaSP) for performing removal activities at the retention basin site will be prepared by the remediation contractor and approved by DTSC prior to commencement of work.

18. SITE SECURITY

The Mandalay Generating Station is an operating facility and is gated and guarded to prevent unauthorized access. The site is surrounded by fences that are eight feet high, with outward-facing barbed-wire extensions (see photos below). The site also has an electronic surveillance system.

19. CONTINGENCY POST-CLOSURE PLAN

Soil and groundwater at the retention basin site will be remediated as described in **Section 12** above, and **Appendices B** and **E**. Post-remediation soil and groundwater data will be assessed to demonstrate compliance with the Closure Performance Standards presented in **Section 11**. Further investigation of site media will be performed as the situation dictates, in consultation with DTSC.

In addition, on-going groundwater monitoring to assess the efficacy of the treatment program (**Section 15**) will be performed. An outline for the post-closure monitoring plan is presented in **Appendix C**. Trend analyses using post-closure groundwater monitoring data, continuing for a maximum of five years, will be performed to demonstrate compliance with the Closure Performance Standards presented in **Section 11**.

If it cannot be demonstrated that Closure Performance Standards have been met for groundwater, then alternative treatment methods will be evaluated. In the event that the Closure Performance Standards are not met after five years, SCE will implement the Contingency Post-Closure Plan described below.

Under the Contingency Post-Closure Plan SCE would close the retention basin site to meet industrial closure (restricted land use standards). A Land-Use Covenant (LUC) and Implementation and Enforcement Plan (IEP) would be provided and approved by DTSC.

Industrial closure can be achieved in accordance with Closure Performance Standards either by demonstrating that no COPCs are identified for the retention basin site, or, alternatively, if one or more COPCs are identified, by performing a risk assessment demonstrating that the resulting risk levels for the COPCs are within prescribed standards for industrial site closure.

Closure Performance Standards for the retention basin site would be expressed in terms of risk, by requiring that risk levels for human receptors potentially exposed to the identified COPCs are within USEPA and DTSC prescribed standards for industrial closure. USEPA guidance indicates that a carcinogenic risk probability between 1 in 10,000 and 1 in 1,000,000 (1×10^{-4} and 1×10^{-6}) is considered to be both safe and protective of public health. Accordingly, a carcinogenic risk probability of 1×10^{-5} will be adopted to be protective of future industrial workers. A hazard index of 1 will be used as the target criterion for evaluating potential non-carcinogenic health effects.

On the basis of these determinations, **Figure 5** indicates there are currently no complete exposure routes for aquatic or terrestrial receptors. . The CSM may be modified based on any determinations indicating that future conditions differ from those depicted in **Figure 5**. If complete exposure routes are identified, closure performance standards may need to be met to achieve protection of ecological receptors and the environment. The ecological and environmental closure performance standards would include water quality criteria, such as the most protective criteria protective of aquatic organisms in the California Toxics Rule or the California Ocean Plan. These would be used to examine any constituents that may reach the canal in the future.

The suite of COCs analyzed and reported in the site characterization reports (listed in **Tables 1** through **3**) will be evaluated for site closure. Each COC can potentially become a COPC according to the DTSC criteria for identifying statistically elevated chemical concentrations.

Closure performance standards for the retention basin site are summarized below:

a. The closure performance standard for metals in soil will be background, or the risk-based concentration for industrial site closure (as noted above and based on **Figure 5**), whichever is greater.

b. The closure performance standard for metals in groundwater will be background, or the risk-based concentrations protective of human receptors, for industrial site closure (as noted above and based on **Figure 5**), whichever is greater. In the event that the MCL is found to be lower than risk-based concentrations and greater than background, then the MCL will be used as the closure performance standard for metals in groundwater. For chemicals that have no MCL (e.g., vanadium), a risk-based standard would be used in place of the MCL.

c. Risk-based closure standards will be developed as needed if additional complete exposure routes are identified after updating the CSM to account for post-remediation data. **Figure 5**, the pre-remediation CSM, would be updated under this scenario.

A Closure Certification Report (**Section 16**) will be generated to demonstrate that these closure performance standards are met following remediation.

If the alternative treatment methods are unsuccessful in demonstrating that Closure Performance Standards can be met for groundwater, then a Post-Closure Permit Application will be submitted.

Tables

Table 1
Summary of Frequency of Occurrence of Detects and Non-detects for Soil at
Mandalay Generating Station
August 1997 through January 2006

		Compliance[1,2]					Background[3]				
Parameter	**Units**	**N**	**NonDetects**	**% detects**	**Minimum**	**Maximum**	**N**	**NonDetects**	**% detects**	**Minimum**	**Maximum**
Aluminum	mg/kg	206	0	100%	1,030	10,100	36	0	100%	1,500	2,700
Antimony	mg/kg	250	187	25%	0.1	8.21	51	50	2%	0.25	0.63
Arsenic	mg/kg	250	0	100%	0.6	110	51	0	100%	0.52	2.4
Barium	mg/kg	250	0	100%	11	640	51	0	100%	19	250
Beryllium	mg/kg	250	50	80%	0.05	1.04	51	10	80%	0.05	0.2
Cadmium	mg/kg	250	113	55%	0.05	1.03	51	23	55%	0.05	0.24
ChromiumVI	mg/kg	250	248	1%	0.25	5.2	36	36	0%	0.8	1.25
Chromium,Total	mg/kg	250	0	100%	2.1	177	36	0	100%	2.8	64
Cobalt	mg/kg	250	0	100%	1.07	33.3	51	0	100%	1.1	9.7
Copper	mg/kg	250	0	100%	1.6	546	51	0	100%	1.8	6.7
Iron	mg/kg	250	0	100%	3,400	324,000	36	0	100%	4,400	140,000
Lead	mg/kg	250	0	100%	0.99	130	51	0	100%	1.2	8.4
Mercury	mg/kg	250	131	48%	0.005	0.62	51	23	55%	0.005	0.12
Molybdenum	mg/kg	250	3	99%	0.1	18.8	51	18	65%	0.1	2.1
Nickel	mg/kg	250	0	100%	2.31	596	51	0	100%	2.5	8.8
Selenium	mg/kg	250	244	2%	0.25	9.64	51	51	0%	0.25	0.25
Silver	mg/kg	250	237	5%	0.05	2.9	51	51	0%	0.05	0.05
Thallium	mg/kg	250	233	7%	0.05	13	51	51	0%	0.25	0.25
Vanadium	mg/kg	250	1	100%	2.5	6,720	51	0	100%	5.9	420
Zinc	mg/kg	250	0	100%	6.17	220	51	0	100%	7.5	22
Manganese	mg/kg	97	0	100%	34	250	36	0	100%	65	440
Nitrate	mg/kg	97	97	0%	1	1	12	12	0%	1	1
pH(field)	mg/kg	151	0	100%	3.74	9.56	24	0	100%	6.82	9.31
pH(lab)	mg/kg	206	0	100%	4.96	9.4	36	0	100%	6.96	8.93

Notes: Detected < 10%

1 - Compliance samples represent the soil Exposure Area (Area where historic boiler chemical cleaning operations may have led to soil contamination)
2 - A total of 73 soil borings in the Exposure Area were sampled.
3 - The background data shown include the 15 McGrath background samples

Table 2a
Summary of Frequency of Occurrence of Detects and Non-detects for Soil Gas Using Method 8260B at Mandalay Generating Station
November 2004

			Compliance[1,2]		Method Detection	Range of Concentrations
Parameter	**Units**	**N**	**NonDetects**	**% detects**	**Limit**	**Detected**
Benzene	ug/l	37	37	0%	1.0	ND
Carbon tetrachloride	ug/l	37	37	0%	1.0	ND
Chloroethane	ug/l	37	37	0%	1.0	ND
Chloroform	ug/l	37	37	0%	1.0	ND
1,2-Dichloroethane	ug/l	37	37	0%	1.0	ND
1,1-Dichloroethane	ug/l	37	37	0%	1.0	ND
cis 1,2-Dichloroethene	ug/l	37	37	0%	1.0	ND
trans 1,2-Dichloroethene	ug/l	37	37	0%	1.0	ND
1,1-Dichloroethene	ug/l	37	37	0%	1.0	ND
Ethylbenzene	ug/l	37	37	0%	1.0	ND
Freon-113	ug/l	37	37	0%	5.0	ND
Freon-112	ug/l	37	37	0%	1.0	ND
Isobutane (tracer gas)	ug/l	37	37	0%	10.0	ND
Methylene Chloride	ug/l	37	37	0%	5.0	ND
1,1,1,2-Tetrachloroethane	ug/l	37	37	0%	1.0	ND
1,1,2,2-Tetrachloroethane	ug/l	37	37	0%	1.0	ND
Tetrachloroethene	ug/l	37	37	0%	1.0	ND
Toluene	ug/l	37	37	0%	1.0	ND
1,2,3-Trichlorobenzene	ug/l	37	37	0%	1.0	ND
1,2,4-Trichlorobenzene	ug/l	37	37	0%	1.0	ND
1,1,1-Trichloroethane	ug/l	37	37	0%	1.0	ND
1,1,2-Trichloroethane	ug/l	37	37	0%	1.0	ND
Trichloroethene	ug/l	37	37	0%	1.0	ND
Trichlorofluoromethane	ug/l	37	37	0%	5.0	ND
Vinyl chloride	ug/l	37	37	0%	5.0	ND
m-Xylene & p-Xylene	ug/l	37	37	0%	1.0	ND
o-Xylene	ug/l	37	37	0%	1.0	ND

Notes:

1 - Compliance samples represent the soil gas Exposure Area (Area where historical boiler chemical cleaning operations may have led to contamination)

2 - A total of 37 soil gas probe locations in the Exposure Area were sampled.

3 - Samples from all locations were analyzed by an on-site mobile laboratory using Method 8260B (Table 2a), and in addition, samples were collected in Summa canisters at six of the 37 locations and analyzed using Method TO-14A (Table 2b). VOCs were detected only in the Summa canister analyses, which have lower detection limits.

Definitions:

ND - Non Detect

Table 2b
Summary of Frequency of Occurrence of Detects and Non-detects for Soil Gas Using Method TO-14A at Mandalay Generating Station
November 2004

			Compliance[1,2]		Method Detection	Range of Concentrations	Residential
Parameter	**Units**	**N**	**NonDetects**	**% detects**	**Limit**	**Detected**	**CHHSL[4]**
Acetone	ug/l	6	0	100%	0.0048	0.0356 to 0.1258	NA[5]
PCE	ug/l	6	2	67%	0.0140	0.0292 to 0.0598	0.18
Toluene	ug/l	6	3	50%	0.0075	0.0079 to 0.0094	135
1,1,1-TCA	ug/l	6	2	67%	0.0109	0.0109 to 0.0152	991
Total Xylenes	ug/l	6	3	50%	0.0087	0.0091 to 0.0135	319

Notes:

1 - Compliance samples represent the soil gas Exposure Area (Area where historical boiler chemical cleaning operations may have led to contamination.)

2 - A total of 37 soil gas probe locations in the Exposure Area were sampled.

3 - Samples from all locations were analyzed by an on-site mobile laboratory using Method 8260B (Table 2a), and in addition, samples were collected in Summa canisters at six of the 37 locations and analyzed using Method TO-14A (Table 2b). VOCs were detected only in the Summa canister analyses, which have lower detection limits.

4 - California Human Health Screening Levels for Shallow Soil Gas (vapor intrusion), Residential Land Use (California EPA, 2005)

5 - Not Available

Table 3
Summary of Frequency of Occurrence of Detects and Non-detects for Groundwater at
Mandalay Generating Station
September 2001 through June 2006

			Compliance[1] [2](Downgradient)							Background[3] (Upgradient)					
Group	**Chemical**	**Units**	**N**	**Detects**	**Non- Detects**	**% Detect**	**Minimum**	**Maximum**	**N**	**Detects**	**Non- Detects**	**% Detect**	**Minimum**	**Maximum**
Inorganics														
	Nitrate	ug/l	494	343	151	69	5.6	39,000	20	20	0	100	58	48,000
	pH		494	494	0	100	6.8	8.1	20	20	0	100	6.6	7.7
	Aluminum	ug/l	494	65	429	13	10	920	20	4	16	20	16	67
	Antimony	ug/l	494	2	492	0.4	5.7	6.1	20	0	20	0	NA	NA
	Arsenic	ug/l	494	326	168	66	2	34	20	1	19	5	2.2	2.2
	Barium	ug/l	494	494	0	100	12	390	20	20	0	100	42	180
	Beryllium	ug/l	494	10	484	2	0.41	0.93	20	0	20	0	NA	NA
	Cadmium	ug/l	494	218	276	44	0.5	9.2	20	2	18	10	0.62	1.1
	Chromium, Total	ug/l	494	340	154	69	1	950	20	13	7	65	1.1	40
	Cobalt	ug/l	494	480	14	97	0.2	26	20	19	1	95	0.53	2.4
	Copper	ug/l	494	261	233	53	2	39	20	8	12	40	2	6.1
	Iron	ug/l	494	370	124	75	20	11,000	20	14	6	70	22	310
	Lead	ug/l	494	10	484	2	1	3	20	0	20	0	NA	NA
	Manganese	ug/l	494	494	0	100	17	5,400	20	20	0	100	18	2,200
	Mercury	ug/l	494	1	493	0.2	0.11	0.11	20	0	20	0	NA	NA
	Molybdenum	ug/l	494	494	0	100	3.2	120	20	20	0	100	8.5	21
	Nickel	ug/l	494	479	15	97	2	1,100	20	16	4	80	3.1	23
	Selenium	ug/l	494	153	341	31	2	14	20	3	17	15	2.1	2.5
	Silver	ug/l	494	2	492	0.4	0.54	2.6	20	0	20	0	NA	NA
	Thallium	ug/l	494	3	491	1	0.6	0.84	20	0	20	0	NA	NA
	Vanadium	ug/l	494	283	211	57	3.6	12,000	20	1	19	5	2.8	2.8
	Zinc	ug/l	494	94	400	19	10	1,700	20	1	19	5	23	23
Organics														
	2-Chlorotoluene	ug/l	522	35	487	7	2.1	390	19	0	19	0	NA	NA
	Chlorobenzene	ug/l	522	4	518	1	1.5	5.9	19	0	19	0	NA	NA
	1,1-Dichloroethane (1,1-DCA)	ug/l	522	1	521	0.2	2	2	19	0	19	0	NA	NA
	1,2-Dichlorobenzene (o-DCB)	ug/l	522	23	499	4	1.6	73	19	0	19	0	NA	NA
	1,3-Dichlorobenzene (m-DCB)	ug/l	522	1	521	0.2	1.7	1.7	19	0	19	0	NA	NA
	1,4-Dichlorobenzene (p-DCB)	ug/l	522	14	508	3	1.7	14	19	0	19	0	NA	NA

Notes:

1 - Compliance samples represent the groundwater Exposure Area (Area where historic boiler chemical cleaning operations may have led to groundwater contamination.)
2 - A total of 28 monitoring wells in the Exposure Area were sampled.
3 - Well MW-6

Definitions:

NA - Not applicable

Analytical Test Methods
Mandalay Generating Station

Table 4

	Soil		Soil Gas		Groundwater	
Monitoring Parameter	EPA Method	Practical Quantitation Limit	EPA Method	Practical Quantitation Limit	EPA Method	Practical Quantitation Limit
General Mineral						
pH	9045C	10 mg/kg			SM4500 H+B	
Nitrate	9056	2 mg/l			300	5 mg/l
Aluminum	6020	10 mg/kg			200.8	25 ug/l
Manganese	6020	5 mg/kg			200.7	10 ug/l
Metals						
Antimony	6020	0.5 mg/kg			200.8	2.5 ug/l
Arsenic	6020	0.5 mg/kg			200.8	2 ug/l
Barium	6020	1.0 mg/kg			200.8	2.5 ug/l
Beryllium	6020	0.1 mg/kg			200.8	0.5 ug/l
Cadmium	6020	0.1 mg/kg			200.8	0.5 ug/l
Total Chromium	6020	1.0 mg/kg			200.8	1 ug/l
Chromium IV	7196	2 mg/kg			218.6	0.3 ug/l
Cobalt	6020	0.2 mg/kg			200.8	0.5 ug/l
Copper	6020	0.5 mg/kg			200.8	2.5 ug/l
Iron	6010	10 mg/kg			200.7	20 ug/l
Lead	6020	0.5 mg/kg			200.8	1 ug/l
Mercury	7471	10 ug/kg			245.1	0.1 ug/l
Molybdenum	6020	0.5 mg/kg			200.8	0.5 ug/l
Nickel	6020	0.5 mg/kg			200.8	4 ug/l
Selenium	6020	0.5 mg/kg			200.8	2 ug/l
Silver	6020	0.1 mg/kg			200.8	1 ug/l
Thallium	6020	0.5 mg/kg			200.8	1 ug/l
Vanadium	6020	5.0 mg/kg			200.8	2.5 ug/l
Zinc	6020	5.0 mg/kg			200.8	10 ug/l
Volatile Organic Compounds						
VOCs	8260B	5 ug/kg	8260B	1-5 ug/l	8260B	1-5 ug/l
VOCs			TO-14A	0.0048 - 0.014 ug/l		

Data Source is P. Hamilton

Figures

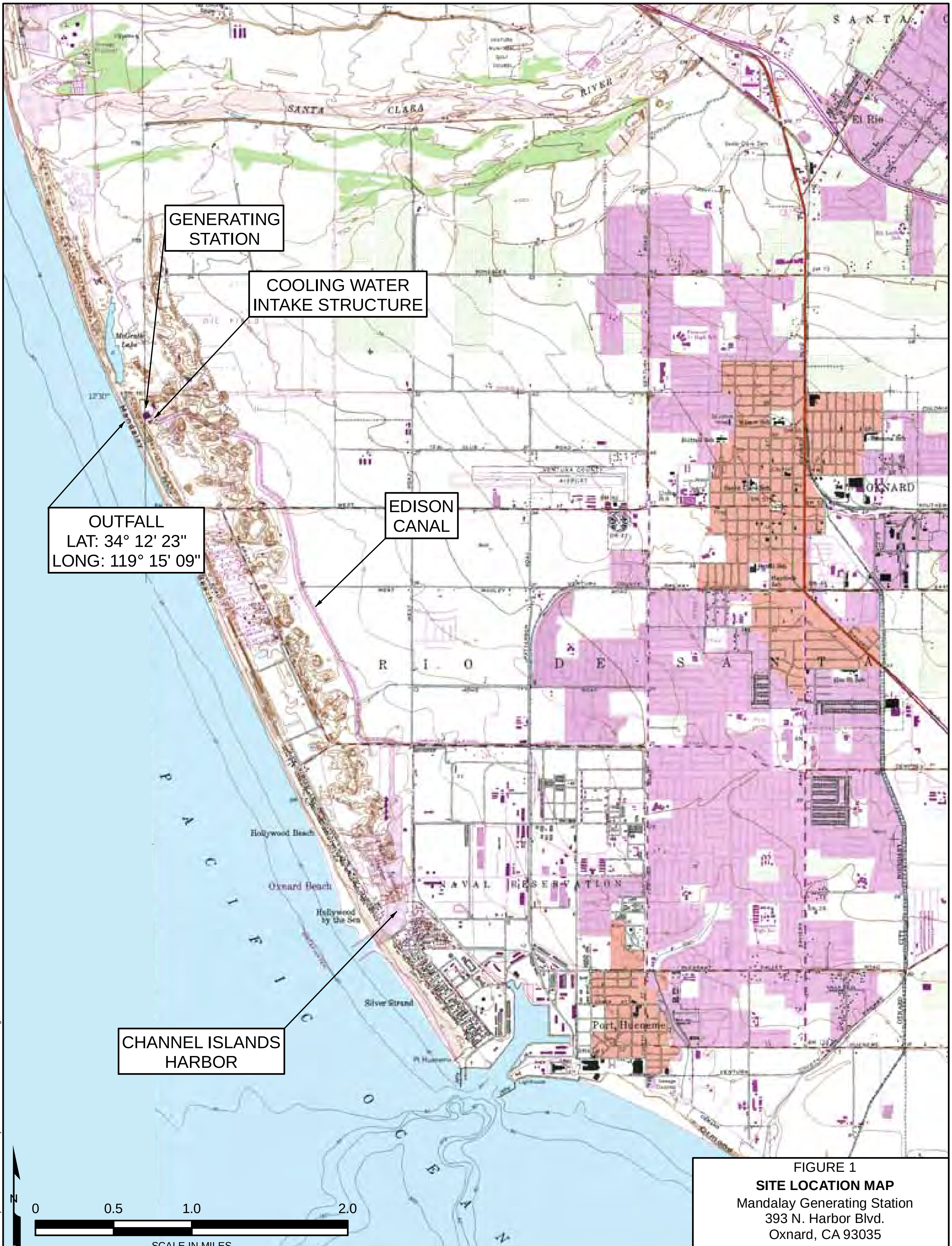


FIGURE 1
SITE LOCATION MAP
Mandalay Generating Station
393 N. Harbor Blvd.
Oxnard, CA 93035
Source: USGS 7.5" Quadrangle, Oxnard, CA

S:\Current Projects\15124 SCE Mandalay CDR\GIS\mxd\location.mxd 30-Aug 2007 CM

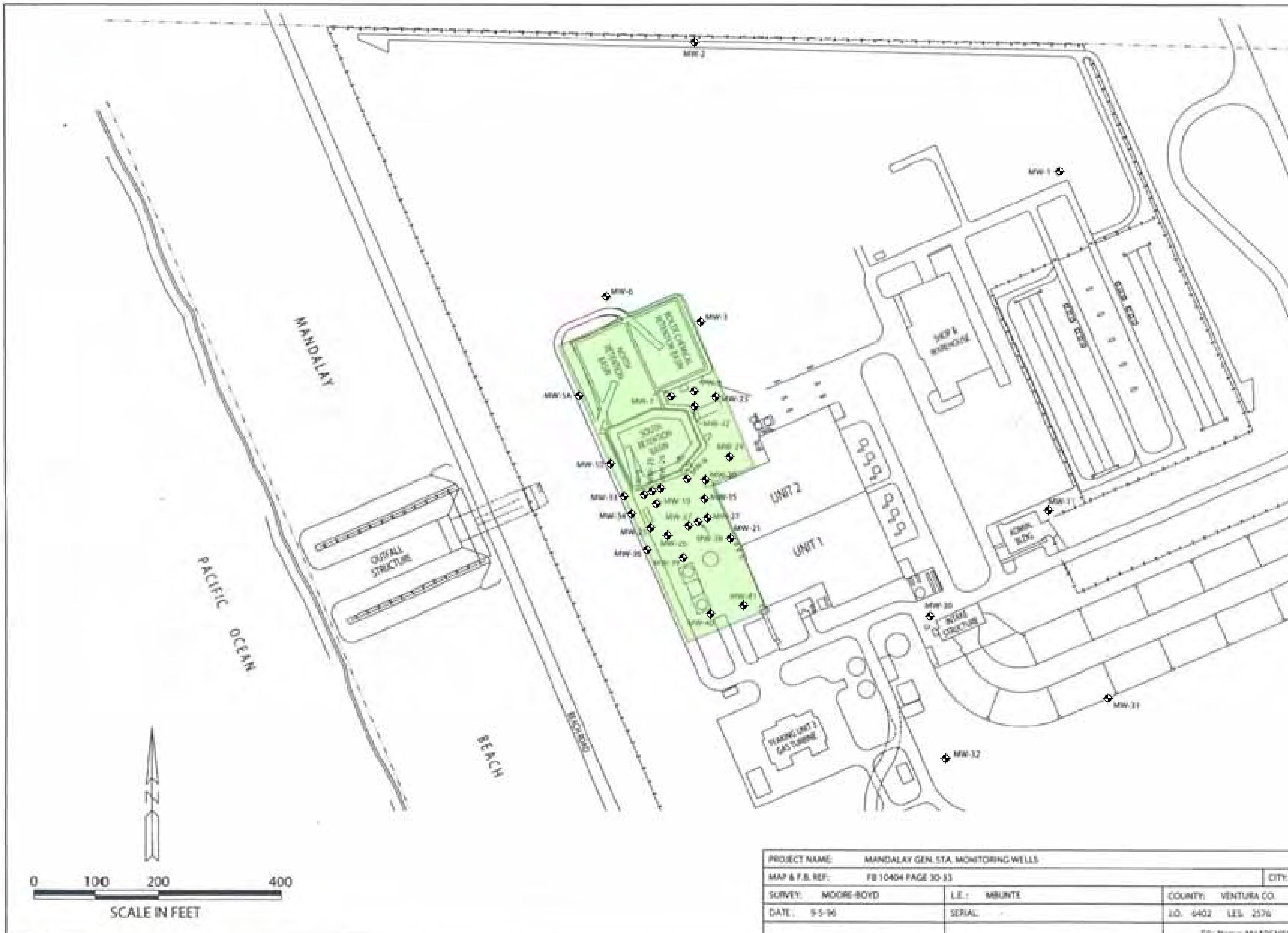


FIGURE 2

LEGEND

- MONITORING WELL
- TARGETED AREA OF REMEDIATION

PROJECT NAME: MANDALAY GEN. STA. MONITORING WELLS			M.S. -
MAP & F.B. REF: FB 10404 PAGE 30-33			CITY: OXNARD
SURVEY: MOORE-BOYD	L.E.: MBUNTE	COUNTY: VENTURA CO.	EDISON
DATE: 9-5-96	SERIAL: -	J.O. 6402 LES. 2576	
		File Name: M:\ARCHIVI\DRAWING\ .DWG MAB2576	

Location of Soil Borings
Mandalay Generating Station

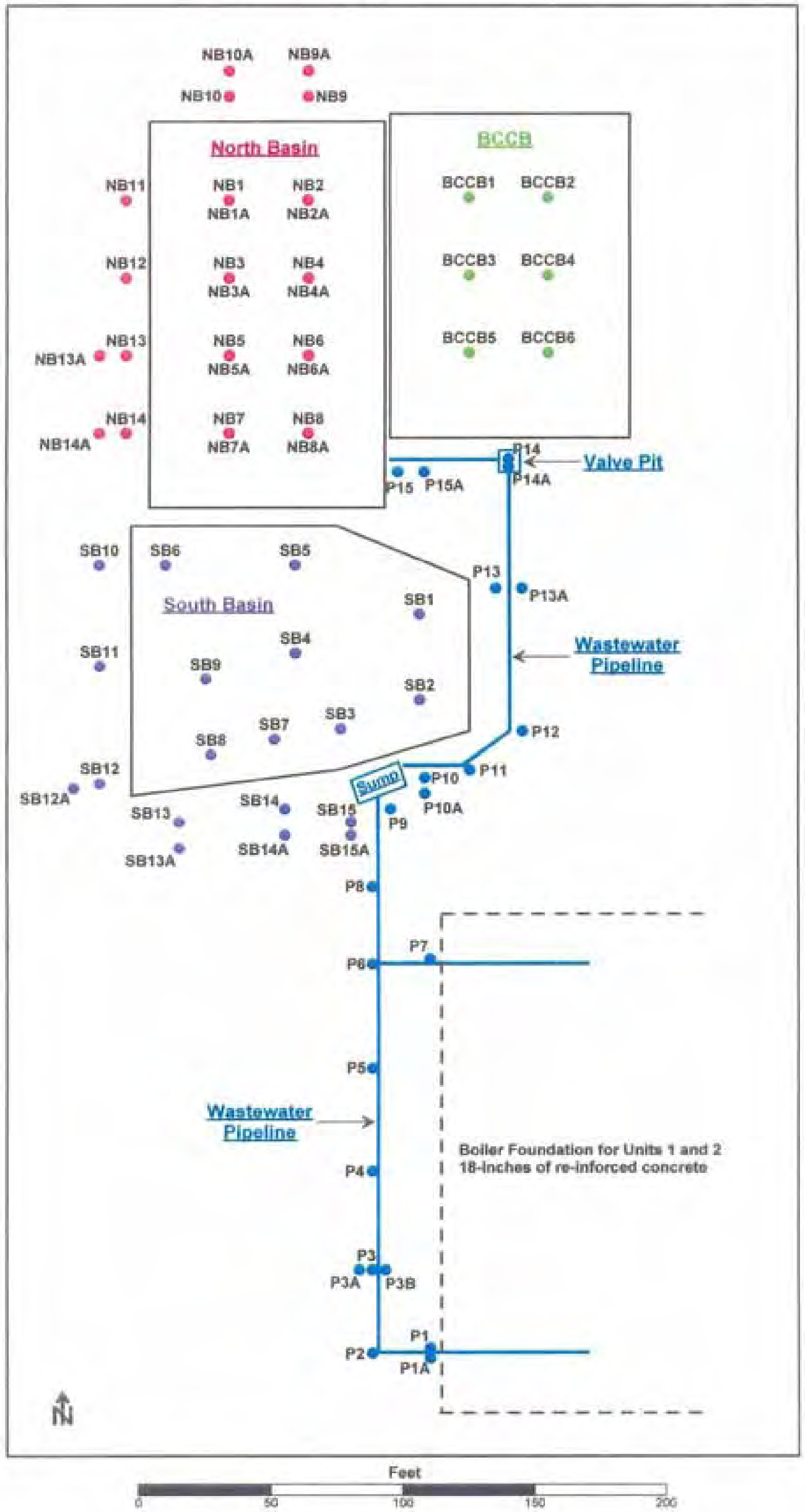
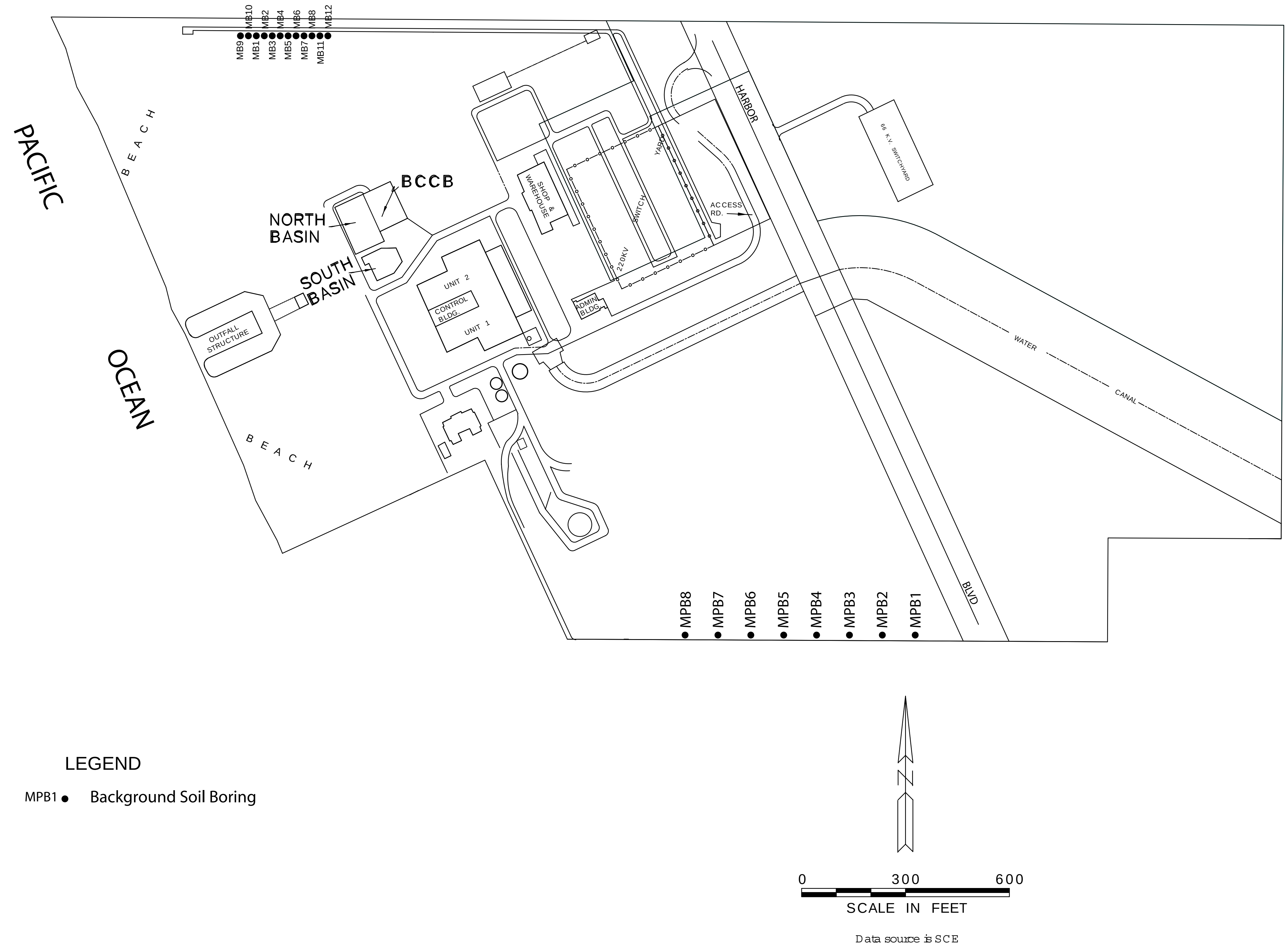


FIGURE 3

Data source is P. Hamilton (2006)



Location of Background Soil Borings
Mandalay Generating Station
Figure 4

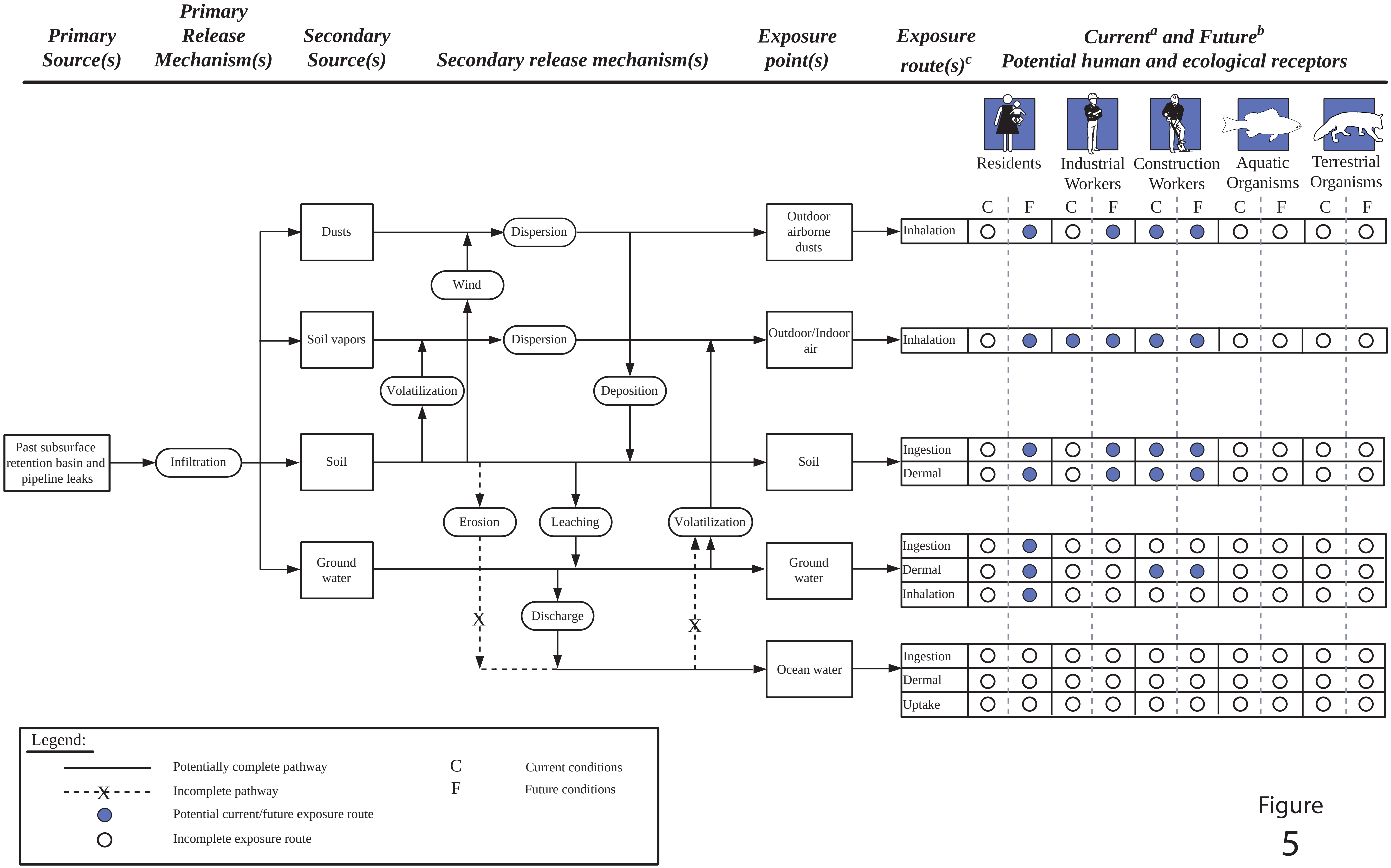


Figure 5

Notes:

a) Current receptor based on 2007 site conditions

b) Future receptor based on unrestricted site conditions that could potentially exist after the generating station is decommissioned and removed.

c) Exposure routes were based on data available in 2007. Thus, future exposure routes may change following retention basin remediation and collection of associated data.

Pre-remediation Human Health and Ecological Conceptual site model (CSM) for current and future (unrestricted) site use.

Appendix A REPRESENTATIVE CHEMICAL ANALYSIS BOILER CHEMICAL CLEANING WASTE

TABLE 4.2-1

RESULTS[a] OF CHEMICAL ANALYSES OF BOILER CLEANING WASTES

Sample I.D.	STLC[b]	L-DCS-85-9F[c]	L-DCS-85-9FF[c]	L-DCS-85-9S[d]	L-DCS-85-9V[d]
Date Sampled:	--	5/15-16/85	7/20-21/85	6/3/85	7/5/85
Sb	15	0.002	<0.002	0.005	<0.002
As	5.0	0.008	<0.001	<0.001	<0.001
Ba	100	0.091	0.16	<0.012	0.023
Be	0.75	<0.004	<0.004	<0.004	<0.004
Cd	1.0	0.003	<0.003	<0.003	<0.003
Cr VI	5	<0.015	0.019	<0.015	0.017
Cr	560	0.25	1.3	0.65	3.3
Co	80	0.34	0.20	<0.026	0.12
Cu	25	114 [34][e]	52 [37][e]	0.008	<0.007
F	180	127	110	50	100
Pb	5.0	1.4	<0.002	<0.05	<0.002
Hg	0.2	0.0004	<0.0003	<0.0003	<0.0003
Mo	350	0.054	0.082	0.54	2.2
Ni	20	29 [29][e]	1.5	0.13	0.93
Se	1.0	<0.001	<0.001	<0.001	<0.001
Ag	5	0.012	<0.005	<0.005	<0.005
Ti	7.0	<0.005	<0.005	<0.005	<0.005
V	24	0.047	0.35	<0.015	0.19
Zn	250	17	16	0.066	0.38
Aldrin	0.14	ND (<0.02)	ND (<0.005)	ND (<0.001)	ND (<0.005)
Alpha-BHC	--	ND (<0.02)	ND (<0.005)	ND (<0.001)	ND (<0.005)
Beta-BHC	--	ND (<0.02)	ND (<0.005)	ND (<0.001)	ND (<0.005)
Delta-BHC	--	ND (<0.02)	ND (<0.005)	ND (<0.001)	ND (<0.005)
Gamma-BHC (Lindane)	0.4	ND (<0.02)	ND (<0.005)	ND (<0.001)	ND (<0.005)
Chlordane	0.25	ND (<0.04)	ND (<0.01)	ND (<0.002)	ND (<0.01)
p,p' DDD	0.1	ND (<0.02)	ND (<0.005)	ND (<0.001)	ND (<0.005)
p,p' DDE	0.1	ND (<0.02)	ND (<0.005)	ND (<0.001)	ND (<0.005)
p,p' DDT	0.1	ND (<0.02)	ND (<0.005)	ND (<0.001)	ND (<0.005)
2,4 - D	10	ND (<1.0)	ND (<0.1)	ND (<0.02)	ND (<0.01)
Dieldrin	0.8	ND (<0.02)	ND (<0.005)	ND (<0.001)	ND (<0.005)
Dioxin	0.001	ND (<0.002)	ND (<0.001)	ND (<0.001)	ND (<0.0005)
Endosulfan I(alpha)	--	ND (<0.02)	ND (<0.005)	ND (<0.001)	ND (<0.005)
Endosulfan II(beta)	--	ND (<0.02)	ND (<0.005)	ND (<0.001)	ND (<0.005)
Endosulfan sulfate	--	ND (<0.02)	ND (<0.005)	ND (<0.001)	ND (<0.005)
Endrin	0.02	ND (<0.02)	ND (<0.005)	ND (<0.001)	ND (<0.005)
Endrin Aldehyde	--	ND (<0.02)	ND (<0.005)	ND (<0.001)	ND (<0.005)
Heptachlor	0.47	ND (<0.02)	ND (<0.005)	ND (<0.001)	ND (<0.005)
Heptachlor Epoxide	--	ND (<0.02)	ND (<0.005)	ND (<0.001)	ND (<0.005)
Kepone	2.1	ND (<0.02)	ND (<0.005)	ND (<0.001)	ND (<0.005)
Pentachlorophenol	1.7	ND (<0.25)	ND (<0.02)	ND (<0.025)	ND (<0.2)
Toxaphene	0.5	ND (<0.1)	ND (<0.025)	ND (<0.005)	ND (<0.025)
Trichloroethylene	204	0.0005	NA	0.0021	ND (<0.0005)
2,4,5 - TP(Silvex)	1.0	ND (<0.2)	ND (<0.02)	ND (<0.004)	ND (<0.02)
2,4,5 - T(Acetic Acid)	--	ND (<0.2)	ND (<0.02)	ND (<0.004)	ND (<0.02)
Arochlor 1016	5.0	ND (<0.02)	ND (<0.005)	ND (<0.001)	ND (<0.005)
Arochlor 1221	5.0	ND (<0.04)	ND (<0.01)	ND (<0.002)	ND (<0.01)
Arochlor 1232	5.0	ND (<0.02)	ND (<0.005)	ND (<0.001)	ND (<0.005)
Arochlor 1242	5.0	ND (<0.02)	ND (<0.005)	ND (<0.001)	ND (<0.005)
Arochlor 1248	5.0	ND (<0.02)	ND (<0.005)	ND (<0.001)	ND (<0.005)
Arochlor 1254	5.0	ND (<0.02)	ND (<0.005)	ND (<0.001)	ND (<0.005)
Arochlor 1260	5.0	ND (<0.02)	ND (<0.005)	ND (<0.001)	ND (<0.005)

NA Not analyzed.
ND Not detected, detection limit in ( ).
a Results in milligrams/liter (mg/l).
b Soluble Threshold Limit Concentration (mg/l) from California Administrative Code Title 22, Division 4, Chapter 30, Article 11.
c Sample of boiler cleaning waste for drum-type boiler.
d Sample of boiler cleaning waste for once-through boiler.
e Results in [ ] are from WET analysis.

41.9S/1-T4.2-1

Source: Hydrogeologic Assessment Report, El Segundo Generating Station (Dames & Moore, 1986)

Appendix B GROUNDWATER REMEDIATION PLANNING INFORMATION

APPENDIX B – GROUNDWATER REMEDIATION PLANNING INFORMATION MANDALAY GENERATING STATION RETENTION BASIN SITE

The proposed approach for selecting and implementing a remedy is outlined below. The proposed approach will be refined based on the results of the field and laboratory testing to confirm the use of the proposed treatment chemicals, as described in this appendix.

- Additional data needs, to design the groundwater treatment plan for metals: perform sampling of sediments from below the water table for leachability/treatability testing:
    - Sampling and chemical analysis of sediments from below the water table will include:
        - upgradient samples and samples within the plume to evaluate the association of (aqueous) nickel and vanadium with aquifer solids;
        - aquifer sediment samples from area affected by the plume for treatability testing;
    - Because of the presence of iron oxides in the sands and the reducing chemical environment at depth, contact of the sediments with air will be minimized to prevent iron oxidation prior to testing;
- Evaluate technical feasibility and develop preliminary cost estimates and timelines for different remediation technologies;
- Select most promising technology or technologies based on site characteristics, the development status of the technology, and cost effectiveness;
- Perform bench-scale testing to determine feasibility of selected technology (immobilization):
    - Prepare flow-through columns with sediment samples obtained within the plume;
    - Pass groundwater containing treatment chemicals (such as calcium polysulfide or zero-valent colloidal iron) through aquifer sediments and monitor concentration of COPCs as a function of pore volume;
    - Pass untreated groundwater through a parallel column to compare effects of simple flushing;
    - After COPC concentrations have stabilized for multiple pore volumes in treated column, pass untreated groundwater through aquifer sediments to evaluate possible remobilization of COPCs after treatment ends;
- Perform initial treatability/injection activities to determine feasibility and effectiveness of selected technology:

  - Based on results from bench-scale testing, inject the recommended dosage of treatment chemicals into the area of the aquifer where the highest contaminant concentrations have been observed, utilizing direct-push technology;
  - Design an injection point array in a pattern which allows for determination of the optimum spacing for complete cross-coverage of the injected material;
  - Place the injection array in such a manner that existing monitoring wells can be utilized for performance monitoring.

- Develop full-scale groundwater treatment system design, timeline, and cost estimates for selected technology.

Appendix C OUTLINE OF POST-CLOSURE GROUNDWATER SAMPLING PROGRAM

APPENDIX C – OUTLINE OF POST-CLOSURE GROUNDWATER SAMPLING PROGRAM
MANDALAY GENERATING STATION RETENTION BASIN SITE

Following are the monitoring goals for the post-closure groundwater sampling program:

1. Verify that the groundwater contamination is not migrating to the canal.
2. Determine the effectiveness of the treatment measures to immobilize the metal contamination.
3. Document clean conditions for three years after the groundwater concentrations reach acceptable levels.

In order to conduct the post-closure groundwater monitoring program, a Sampling and Analysis Plan that includes the following elements will be prepared:

1. Location, Purpose and Construction Details of New Monitoring Wells
2. Field Sampling Equipment
3. Sampling Protocol
    a. List of Wells to be Sampled Quarterly
    b. List of Wells to be Sampled Annually
    c. COC List
4. QA Procedures
5. Reporting

Appendix D BACKGROUND TECHNICAL REPORTS

Appendix D BACKGROUND TECHNICAL REPORTS MANDALAY GENERATING STATION RETENTION BASIN SITE

California Environmental Protection Agency (California EPA), 2005. Use of California Human Health Screening Levels (CHHSLs) in Evaluation of Contaminated Properties. Table 2. January 2005.

CleanHarbors, 2006. Letter to Reliant Energy on acceptance of Retention Basin Solids. November 2006.

Department of Toxic Substances Control (DTSC). 1997. Selecting inorganic constituents as chemicals of potential concern at risk assessments at hazardous waste sites and permitted facilities. Final Policy - Human and Ecological Risk Division. DTSC. February. http://www.dtsc.ca.gov/ScienceTechnology/ftp/backgrnd.pdf.

Department of Toxic Substances Control (DTSC). 2006. Basic Elements of a Closure Plan for Surface Impoundments. April. http://www.dtsc.ca.gov/HazardousWaste/Permits/ Permit Writers Closure TOC.cfm

Hamilton, P. 1996. Water Quality Monitoring Program, Mandalay Generating Station. Report prepared for Southern California Edison. April 1996.

Hamilton, P. 2000. Sampling and Analysis Plan, Wastewater Basin Closure Project. Report prepared for Southern California Edison. August 2000.

Hamilton, P. 2006. Soil Characterization, Mandalay Generating Station. Report prepared for Southern California Edison. April 2006.

Hamilton, P. 2007. Annual Groundwater Monitoring Report, Groundwater Evaluation Monitoring Program, with Fourth Quarter 2006 Sampling Data, Mandalay Generating Station. Report prepared for Southern California Edison. February 9, 2007.

Human and Ecological Risk Division, 2007. Site walk notes by Loveriza Sarmiento on ecological exposure routes at the Mandalay retention basin site. April 26, 2007.

Komex 2004. Project Health and Safety Plan (HaSP) for Soil Vapor Investigation, Mandalay Generating Station, Oxnard, California. May 28, 2004.

Komex 2005a. Soil Gas Survey Report, Mandalay Generating Station. Report prepared for Southern California Edison. January 6, 2005.

Komex 2005b. Final Draft Closure Demonstration Report for the Wastewater Retention Basin at the Long Beach Generating Station, Long Beach California. Report prepared for Southern California Edison. March 17, 2005.

Los Angeles Regional Water Quality Control Board (RWQCB) 2006. Email from Jenny Au to SCE on Beneficial Uses for the Oxnard Sub-basin. May 23, 2006.

Appendix E REMEDIAL ACTION COST ESTIMATES

Appendix E REMEDIAL ACTION COST ESTIMATES MANDALAY GENERATING STATION RETENTION BASIN SITE

BACKGROUND

Based on the findings of the site soil and groundwater investigations referenced in Appendix D, a cost estimate has been developed for remediation of both media. This cost estimate is preliminary and subject to the findings and conclusions from the statistical analyses, COPC identification, human health and environmental risk assessment, and closure performance standards, which have yet to be performed. The assumptions used in preparing the cost estimates for soil removal are as follows:

- Soil beneath the South Retention Basin requires removal, owing to elevated concentrations of arsenic, nickel and vanadium.
- The footprint of the area requiring removal is one hundred-twenty feet (east-west direction; Figure 5) by ninety-five feet (north-south direction; Figure 5), which includes the bottom of the basin, plus half the slope height on all four sides of the basin.
- Excavation will be to a depth of five feet, which is the seasonal low water level.
- Removal of this volume of material will result in an average concentration of the metals of concern noted earlier being equal to, or less than their respective average background concentrations. (Background concentrations for metals and groundwater are presented in **Tables 1** and **3**, respectively.)

Soil Removal Action

The attached Table E-1 outlines the tasks, unit costs, and total costs for three potential scenarios of contaminated soil removal and disposal. These three scenarios include a situation where: 1) The excavated soil is characterized as non-hazardous and can be disposed at a local landfill, 2) The excavated soil is California-only hazardous, or 3) The excavated soil is RCRA-hazardous. Most of the tasks and related costs are the same for each of the scenarios. The main cost differentials are related to transportation and disposal fees.

The initial task will be development of a Work Implementation Plan (WIP) and Health and Safety Plan (HASP). The WIP will include the plans for mobilization, basin liner removal, excavation and stockpiling of impacted soils, soil stockpile characterization and waste profiling, loading, transportation and disposal of impacted soil, clean soil backfill and liner restoration activities, and demobilization. The HASP will include health information on the contaminants being removed, requirements for personal protective equipment, air monitoring, and engineering controls to limit exposure. Once the WIP and HASP are approved, remedial activities can begin. Since the basin is an integral part of the generating station operation, SCE will have to coordinate with the current owner/operator to plan the removal action during a period that will not adversely affect plant operation.

Soil remedial activities will initiate with monitoring of background air for contaminants of concern. Once the background air monitoring has been established, the HDPE basin liner will be removed. After the liner is removed, the original asphalt liner will be removed and disposed. Once the underlying contaminated soil is exposed, excavation can commence. Contaminated soil will be removed and stockpiled for characterization. Once the material has been characterized, it will be transported to the proper facility. Following excavation, confirmation samples will be collected in accordance with the WIP. Excavation will continue until the confirmation samples indicate the contaminated soil has been removed. Once excavation is complete, groundwater treatment chemicals will be injected into the underlying aquifer. The treatment chemicals and injection spacing will be determined from treatability testing outlined in Appendix B. Following injection operations, clean, compacted backfill material will be placed to bring the soil back to original basin grade. After compacted soil placement, the HDPE liner will be replaced and the basin returned to operation.

Groundwater Treatment

The attached Table E-2 outlines the tasks, unit costs, and total costs for injection of treatment chemicals into the aquifer contaminated by arsenic, nickel and vanadium. The treatment strategy assumed for this cost estimate is immobilization. The costs include aquifer media sampling and treatability testing, and implementation of the selected remedial technology (**Appendix B**). Based on previous limited site geochemical evaluation, the injection of calcium polysulfide was recommended as a possible chemical which could bind or precipitate the metals of concern, on to aquifer solids, removing them from the dissolved phase in groundwater. The following assumptions were made in developing the groundwater remediation cost estimate:

- Based on the plume dimensions developed from the groundwater monitoring investigations, it is estimated that the treatment area is approximately two hundred feet wide and one hundred-eighty feet downgradient from the south edge of the basin.
- Ten foot injection spacing is anticipated to be appropriate for the site, resulting in an array of a maximum of 360 injection points. It is anticipated that up to 72 injection points will initially be emplaced within the limits of the defined groundwater plume. Additional injection points or modifications may be needed based on the confirmation sampling results.
- Injection will be conducted over a ten foot aquifer depth interval, based on information developed from the groundwater monitoring investigations (**Section 4.4** and **Section 10**).
- It was assumed that calcium polysulfide, or a similar treatment chemical would be found to be effective for binding or precipitating the metals of concern on to aquifer solids. An estimate of approximately 300 gallons of treatment solution will be injected for each injection point. However, a maximum of five thousand gallons of treatment solution is conservatively proposed, as requested by the Department.

Based on the recommendations of the project geochemist, appropriate aquifer solids matrix will be collected within the metal plume area for column/treatability testing. Once the treatability testing is completed, a remedial injection plan can be developed to determine the injection point spacing, injection depth intervals, and treatment chemical concentration. Prior to initiation of the full-scale remedial activities, an initial injection program will be developed and implemented (**Appendix B**). It is anticipated that this program will consist of an injection array of ten percent of full scale, or 36 to 72 injection points. The array will placed in the area of highest documented groundwater contamination.

Performance monitoring will be conducted by utilizing existing groundwater monitoring wells. Some direct-push soil sampling may be conducted to determine the effective radial extent of injected material. A WIP and HASP will be prepared and approved by DTSC. A General Waste Discharge Permit for in-situ technology applications will be procured from the Los Angeles Regional Water Quality Control Board, prior to initiation of any injection activities.

Groundwater remedial activities will begin with the marking of the treatment grid and clearing of the injection points for underground utilities. Once the initial and full-scale injection programs are completed and the aquifer treatment reactions are concluded to have been completed, groundwater monitoring of the wells within the plume will be initiated. At the appropriate time as determined by groundwater monitoring results (**Section 15**), a second round of injection may be performed, as necessary.

TABLE E-1
SOIL REMEDIATION COSTS
MANDALAY GENERATING STATION

TASK	UNITS & COSTS						COST TOTALS		
	Lump Sum	$/Ton	Tons	Sub-Total	$/Day	Days	Non-Hazardous	CA-Hazardous	RCRA-Hazardous
Work Implementation Plan/HASP	$ 10,000						$ 10,000	$ 10,000	$ 10,000
Liner Removal & Repair	$ 20,000						$ 20,000	$ 20,000	$ 20,000
Oversight/Monitoring/Sampling					$ 1,000	10	$ 10,000	$ 10,000	$ 10,000
Mob & Demob	$ 5,000			$ 5,000			$ 5,000	$ 5,000	$ 5,000
Excavation & Stockpile		$ 15	3200	$ 48,000			$ 48,000	$ 48,000	$ 48,000
Waste Characterization	$ 10,000						$ 10,000	$ 10,000	$ 10,000
Confirmation Soil Samples	$ 10,000						$ 10,000	$ 10,000	$ 10,000
Backfill & Compaction		$ 25	3200	$ 80,000			$ 80,000	$ 80,000	$ 80,000
Non-Hazardous Waste Disposal									
Transportation		$ 10	3200	$ 32,000			$ 32,000		
Disposal		$ 25	3200	$ 80,000			$ 80,000		
Asphalt Disposal		$25	280	$ 7,000			$ 7,000		
CA-Haz Waste Disposal									
Transportation		$ 50	3200	$ 160,000				$ 160,000	
Disposal		$ 45	3200	$ 144,000				$ 144,000	
RCRA Waste Disposal									
Transportation		$ 50	3200	$ 160,000					$ 160,000
Disposal		$ 100	3200	$ 320,000					$ 320,000
Potential Remedial Chemical Placement							$ 100,000	$ 100,000	$ 100,000
Report	$ 10,000						$ 10,000	$ 10,000	$ 10,000
SUB-TOTAL							$ 422,000	$ 607,000	$ 783,000
Contingency (20%)							$ 82,400	$ 119,400	$ 154,600
GRAND TOTAL							$ 504,400	$ 726,400	$ 937,600

NOTES:

Cubic Yards Asphalt = 140
Assume 2 tons/cubic yard

TABLE E-2
GROUNDWATER REMEDIATION COSTS
MANDALAY GENERATING STATION

TASK	UNITS & COSTS						TOTAL COSTS
	Lump Sum	Injection Point Spacing	# of Injection Points	Depth	Total Linear Feet	$/Linear Foot	
Aquifer Soil Acquisition	$ 10,000						$ 10,000
Treatability/Column Testing	$ 25,000						$ 25,000
Work Implementation Plan/HASP	$ 5,000						$ 5,000
Utility Clearance	$ 5,000						$ 5,000
Injection Array		10 feet	360	10 feet	3,600		
Injection Contractor Cost						$ 35	
Injecton Chemical Cost						$ 50	
Sub-Total Injection Costs					3,600	$ 85	$ 306,000
SUB-TOTAL							$ 351,000
Assumed Second Injection Event							$ 306,000
GRAND TOTAL							$ 657,000

Appendix F SCE FINANCIAL ASSURANCE DOCUMENT

SOUTHERN CALIFORNIA
EDISON®

An *EDISON INTERNATIONAL®* Company

September 24, 2007

Florence Gharibian
Department of Toxic Substances Control
1011 North Grandview avenue
Glendale, CA 91201

Re: **Southern California Edison**
Mandalay Generating Station
Boiler Chemical Cleaning Retention Basin
Financial Assurance

Southern California Edison Company (SCE) is submitting the attached documentation for use of the "Financial Test" to demonstrate financial assurance at the subject facility.

Should you have any questions or require additional information, please contact me directly at (626) 302-9711.

Sincerely,

//original signed by//

Stanley L. Marsh
Senior Environmental Specialist
Environment Health & Safety

Attachment

Cc: Ronald Jensen
Richard Tom
John Butler
Randall Weidner

P.O. Box 800
Rosemead, CA 91770

September 24, 2007

Florence Gharibian
1011 North Grandview Avenue
Glendale, CA 91201

I am the chief financial officer of the Southern California Edison Company at 2244 Walnut Grove Avenue, Rosemead, California, 91770. This letter is in support of the use of the financial test to demonstrate financial responsibility for liability coverage and closure and/or post-closure care as specified in California Code of Regulations (Cal. Code of Regs.), Title 22, Division 4.5, Chapter 14 and 15, Article 8.

This firm is the owner or operator of the following facility/TTU for which liability coverage for sudden accidental occurrences is being demonstrated through the financial test specified in California Code of Regulations, Title 22, Division 4.5, Chapter 14 and 15, Article 8, Sections 66264.147 and 66265.147.:

None

This firm guarantees through the guarantee specified in Cal. Code of Regs., Title 22, Division 4.5, Chapter 14 and 15, Article 8, Sections 66264.147 and 66265.147, liability coverage for sudden accidental occurrences at the following facility/TTU owned or operated by the following:

Facility	Location	EPA I.D. No.
Reliant Mandalay Generating Station **Owned by Reliant Energy** **Boiler Chemical Cleaning Retention Basin**	**373 N. Harbor Blvd.** **Oxnard, CA 93030**	**CAD000630913**

This firm is the direct or higher tier parent corporation of the owner or operator; and receiving the following value in consideration of the guarantee:

None

This firm owns or operates the following facility[s]/TTU[s]for which financial assurance for liability coverage is not demonstrated either to U.S. Environmental Protection Agency or a state through this financial test and guarantee or through any other financial assurance mechanism as specified in California Code of Regulations, Title 22, Division 4.5, Chapter 14 and 15, Article 8 or substantially equivalent state mechanisms. The current liability coverage not covered by such financial assurance is shown for each facility:

None

In states where U. S. Environmental Protection Agency is not administering the financial requirements of Subpart H of Title 40, Code of Federal Regulations [40 CFR], Parts 264 and 265, this Owner or Operator is demonstrating financial assurance for liability coverage of the following facility[s]/TTU[s] through the use of a test equivalent or substantially equivalent to the financial test specified in California Code of Regulations, Title 22, Division 4.5, Chapter 14 and 15, Article 8. The current liability coverage covered by such a test is shown for each facility:

None

This firm is the Owner or Operator of the following Underground Injection Control facility[ies] for which financial assurance for plugging and abandonment is required under Part 144. The current closure cost estimate, as required by 40 CFR 144.62 is shown for each facility:

None

1. This firm is the Owner or Operator of the following facilities/TTUs for which financial assurance for closure or post-closure is demonstrated through the financial test as specified in Cal. Code of Regs., Title 22, Division 4.5, Chapter 14 and 15, Article 8, Sections 66264.143[f], 66264.145[f], 66265.143[e], and 66265.145[e]. The current closure and/or post-closure cost estimates covered by the test are shown for each facility/TTU:

   None

2. This firm guarantees through the corporate guarantee as specified in Cal. Code of Regs., Title 22, Division 4.5, Chapter 14 and 15, Article 8, Sections 66264.143[f], 66264.145[f], 66265.143[f],and 66265.145[f] for the closure and/or post-closure care of the following facilities/TTUs owned or operated by the guaranteed party. The current cost estimates for the closure or post-closure care so guaranteed are shown for each facility/TTU:

Facility	Closure Cost Estimate	Post-Closure Cost Estimate
Reliant Mandalay Generating Station **Owned by Reliant Energy** **Boiler Chemical Cleaning Retention Basin** **373 N. Harbor Blvd.,** **Oxnard, CA 93030**	**$1,594,600**	**None**

3. In states where the U.S. Environmental Protection Agency is not administering the financial requirements of Subpart H, Title 40 CFR, Parts 264 and 265, this firm as owner, operator or guarantor is demonstrating financial assurance for the closure or post-closure care of the following facilities/TTUs through the use of a financial test equivalent or substantially equivalent to the financial test specified in Cal. Code of Regs, Title 22, Division 4.5, Chapter 14 and 15, Article 8, Sections 66264.143[f], 66264.145[f], 66265.143[f], and 66265.145[f]. The current closure and/or post-closure cost estimates covered by such a test are shown for each facility/TTU:

   None

4. This firm is the owner or operator of the following facilities/TTUs for which financial assurance for closure or, if a disposal facility, post-closure care, is not demonstrated either to U.S. Environmental Protection Agency or a State through the financial test or any other financial assurance mechanism as specified in Cal. Code of Regs., Title 22, Division 4.5, Chapters 14 and 15, Article 8 or equivalent or substantially equivalent State mechanisms. The current closure and/or post-closure cost estimates not covered by such financial assurance are shown for each facility/TTU:

   None

5. This firm is the owner or operator of the following Underground Injection Control facilities for which financial assurance for plugging and abandonment is required under Part 144. The current closure cost estimates are shown for each facility:

   None

This firm is required to file a form 10-K with the Securities and Exchange Commission [SEC] for the latest fiscal year.

The fiscal year of this firm ends on December 31. The figures following are derived from this firm's independently audited, year-end financial statements for the latest completed fiscal year, ended December 31, 2006.

This firm is using Alternative IV.

ALTERNATIVE IV

1.	Sum of current closure and post-closure cost estimates (Total of all cost estimates shown in the paragrapths of the letter to the Director of the Department of Toxic Substances control).............	$	1,594,600
2.	Amount of annual aggregate liability coverage to be demonstrated	$	2,000,000
3.	Sums of lines 1 and 2..	$	3,594,600
4.	Current bond rating of most recent issuance and name of rating service		Moody's A3, S&P BBB+
5.	Date of issuance of bond . . . . Series 2006A Series 2006B Series A-B Series C-D Series E		January 24, 2006 January 24, 2006 April 12, 2006 April 12, 2006 December 11, 2006
6.	Date of maturity of bond . . . . Series 2006A Series 2006B Series A-B Series C-D Series E		February 1, 2036 February 2, 2009 April 1, 2028 November 1, 2033 January 15, 2037
7.	Tangible net worth	$	6,003,000,000
8.	Total assets in the United States (required only if less than 90 percent of assets are located in the United States) . .		26,110,000,000
9.	Is Line 7 at least 10 million?		Yes
10.	Is line 7 at least 6 times line 3?		Yes
11.	Are at least 90% of assets located in the United States? . . . . If not, complete line 12.		Yes
12.	Is line 8 at least 6 times line 3?		Yes

I hereby certify that this letter is worded as specified by the Department of Toxic Substances Control and is being executed in accordance with the requirements of California Code of Regulations, Title 22, Division 4.5, Chapter 14 and 15, Article 8.

//original signed by//

	Thomas M. Noonan
Signature	Typed or Printed
Senior VP and CFO	9/24/2007
Title	Date

Southern California Edison Company
Tangible Net Worth
As of December 31, 2006
(In Millions)

Total Shareholder's Equity	$6,376	2006 Annual Report, Page 43
Less: Intangible assets	373	see below
Tangible Net Worth	$6,003	

Intangible assets details: (Actual Dollars)

within total utility plant --		
intangible plant	526,252,959.12	DPB 2003R, Account 101.050
accum deprec for intangible plant	(269,377,432.07)	DPB 2003R, Accounts 111.030, .105,.210,.220,.260,.315 and .640
	256,875,527.05	
within total current assets --		
prepaid trnsln license - Morongo	1,938,504.00	DPB 5350, account 165.520
prepayment of FTR (cost)	10,752,013.65	DPB 5350, account 165.610
Mountainview RECLAIM inventory	1,110,381.00	Mountainview balance sheet line item
prepaid Big 4 emission credits	850,649.37	Big 4 balance sheet line item detail
deferred proceeds FTR acquisition	0.00	DPB 5350, account 186.937
	14,651,548.02	
within total deferred charges --		
pension fund excess of FASB 87	77,732,000.00	DPB 5350, account 186.392
pension intangible asset	0.00	DPB 5350, account 186.394
unamortized cost LB Op agreement	1,985,097.71	DPB 5350, account 186.845
prepaid software license	4,311,728.38	DPB 5350, account 186.870
	84,028,826.09	
Mountainview emissions credits	13,089,489.34	Mountainview financials
Big 4 emissions related/other intangibles	4,333,255.67	Big 4 balance sheet line item detail
	101,451,571.10	
Total intangible assets	372,978,646.17	

TABLE 4

CLOSURE COST ESTIMATE
(August 2007)

STEP #	CLOSURE ACTIVITY	COST ESTIMATE
1	Treatability/Column Testing for Aquifer Remediation	$35,000
2	Work Implementation Plan/HASP/Utility Clearance for Soil and Ground Water Remediation	$20,000
3	SOIL REMEDIATION	
	Liner Removal & Repair	$20,000
	Oversight/Monitoring/Sampling Labor	$10,000
	Mobilization & Demobilization	$5,000
	Excavation & Stockpile	$48,000
	Waste Characterization	$10,000
	Confirmation Soil Samples	$10,000
	Backfill & Compaction	$80,000
	Transportation & Waste Disposal (Note 1)	$480,000
	Remedial Chemical Injection	$100,000
4	GROUND WATER REMEDIATION	
	Injection Contractor/Injection Chemicals-Initial	$306,000
	Injection Contractor/Injection Chemicals-Secondary	$306,000
5	Closure Certification Report	$10,000
	SUBTOTAL	$1,440,000
	Contingency	$154,600
	TOTAL	$1,594,600

Note 1: Assumes worst-case where soil is RCRA-hazardous, requiring disposal at Class I landfill.

SOUTHERN CALIFORNIA
EDISON®
An *EDISON INTERNATIONAL*® Company

2006 Annual Report

Southern California Edison Company

Southern California Edison Company (SCE) is one of the nation's largest investor-owned electric utilities. Headquartered in Rosemead, California, SCE is a subsidiary of Edison International.

SCE, a 121-year-old electric utility, serves a 50,000-square-mile area of central, coastal and southern California.

Table of Contents

Glossary

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below.

AFUDC	allowance for funds used during construction
ARO(s)	asset retirement obligation(s)
CDWR	California Department of Water Resources
CEC	California Energy Commission
CEMA	catastrophic event memorandum account
CPSD	Consumer Protection and Safety Division
CPUC	California Public Utilities Commission
District Court	U.S. District Court for the District of Columbia
DOE	United States Department of Energy
Duke	Duke Energy Trading and Marketing, LLC
DWP	Los Angeles Department of Water & Power
EITF	Emerging Issues Task Force
EITF No. 01-8	EITF Issue No. 01-8, Determining Whether an Arrangement Contains a Lease
EME	Edison Mission Energy
ERRA	energy resource recovery account
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN 46(R)-6	Financial Accounting Standards Interpretation No. 46(R)-6, Determining Variability to be Considered in Applying FIN 46(R)
FIN 46(R)	Financial Accounting Standards Interpretation No. 46, Consolidation of Variable Interest Entities
FIN 47	Financial Accounting Standards Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations
FIN 48	Financial Accounting Standards Interpretation No. 48, Accounting for Uncertainty in Income Taxes – an interpretation of FAS 109
FSP	FASB Staff Position
GRC	General Rate Case
IRS	Internal Revenue Service
ISO	California Independent System Operator
kWh(s)	kilowatt-hour(s)
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
Midway-Sunset	Midway-Sunset Cogeneration Company
Mohave	Mohave Generating Station
MW	megawatts

MWh	megawatt-hours
Ninth Circuit	United States Court of Appeals for the Ninth Circuit
NRC	Nuclear Regulatory Commission
Palo Verde	Palo Verde Nuclear Generating Station
PBOP	postretirement benefits other than pension(s)
PBR	performance-based ratemaking
PG&E	Pacific Gas & Electric Company
PX	California Power Exchange
QF(s)	qualifying facility(ies)
SAB	Staff Accounting Bulletin
San Onofre	San Onofre Nuclear Generating Station
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric
SFAS	Statement of Financial Accounting Standards issued by the FASB
SFAS No. 71	Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation
SFAS No. 123(R)	Statement of Financial Accounting Standards No. 123(R), Share-Based Payment (revised 2004)
SFAS No. 133	Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and hedging Activities
SFAS No. 143	Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations
SFAS No. 157	Statement of Financial Accounting Standards No. 157, Fair Value Measurements
SFAS No. 158	Statement of Financial Accounting Standards No. 158, Employers' Accounting for Defined Benefit Pension and Other Post-Retirement Plans
SRP	Salt River Project Agricultural Improvement and Power District
The Tribes	Navajo Nation and Hopi Tribe
VIE(s)	variable interest entity(ies)

INTRODUCTION

This MD&A contains "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Forward-looking statements reflect SCE's current expectations and projections about future events based on SCE's knowledge of present facts and circumstances and assumptions about future events and include any statement that does not directly relate to a historical or current fact. Other information distributed by SCE that is incorporated in this report, or that refers to or incorporates this report, may also contain forward-looking statements. In this report and elsewhere, the words "expects," "believes," "anticipates," "estimates," "projects," "intends," "plans," "probable," "may," "will," "could," "would," "should," and variations of such words and similar expressions, or discussions of strategy or of plans, are intended to identify forward-looking statements. Such statements necessarily involve risks and uncertainties that could cause actual results to differ materially from those anticipated. Some of the risks, uncertainties and other important factors that could cause results to differ, or that otherwise could impact SCE, include, but are not limited to:

- the ability of SCE to recover its costs in a timely manner from its customers through regulated rates;
- decisions and other actions by the CPUC, the FERC and other regulatory authorities and delays in regulatory actions;
- market risks affecting SCE's energy procurement activities;
- access to capital markets and the cost of capital;
- changes in interest rates and rates of inflation;
- governmental, statutory, regulatory or administrative changes or initiatives affecting the electricity industry, including the market structure rules applicable to each market;
- environmental regulations that could require additional expenditures or otherwise affect the cost and manner of doing business;
- risks associated with operating nuclear and other power generating facilities, including operating risks, nuclear fuel storage, equipment failure, availability, heat rate, output, and availability and cost of spare parts and repairs;
- the availability of labor, equipment and materials;
- the ability to obtain sufficient insurance, including insurance relating to SCE's nuclear facilities;
- effects of legal proceedings, changes in or interpretations of tax laws, rates or policies, and changes in accounting standards;
- the cost and availability of coal, natural gas, fuel oil, nuclear fuel, and associated transportation;
- the ability to provide sufficient collateral in support of hedging activities and purchased power and fuel;
- the risk of counter-party default in hedging transactions or fuel contracts;
- general political, economic and business conditions;
- weather conditions, natural disasters and other unforeseen events; and
- changes in the fair value of investments and other assets.

Additional information about risks and uncertainties, including more detail about the factors described above, are discussed throughout this MD&A and in the "Risk Factors" section included in Part I, Item 1A of SCE's Annual Report on Form 10-K. Readers are urged to read this entire report, including the information incorporated by reference, and carefully consider the risks, uncertainties and other factors that affect SCE's business. Forward-looking statements speak only as of the date they are made and SCE is not obligated to publicly update or revise forward-looking statements. Readers should review future reports filed by SCE with the Securities & Exchange Commission.

This MD&A is presented in 10 major sections: (1) Management overview; (2) Liquidity; (3) Regulatory Matters; (4) Other Developments; (5) Market Risk Exposures; (6) Results of Operations and Historical Cash Flow Analysis; (7) Acquisitions; (8) Critical Accounting Estimates; (9) New Accounting Pronouncements; and (10) Commitments and Indemnities.

MANAGEMENT OVERVIEW

In 2006, SCE continued effective execution of Edison International's strategic plan, with a focus on implementation of its capital investment plan to meet system growth and ensure reliability and progression toward a set of market rules that permit SCE to procure power efficiently. SCE met and in some cases exceeded what was set out in its 2006 goals associated with the strategic plan as it related to SCE. Principal objectives achieved in 2006 are summarized below:

- Implementation of SCE's capital investment plan to meet system growth and ensure reliability – During 2006, the CPUC authorized, through the 2006 GRC proceeding, a net increase of $134 million in SCE's 2006 base rate revenue and supported SCE's capital investment plan to ensure system reliability. In 2006, SCE undertook new projects to expand its generation, transmission and distribution systems, including pursuing the permitting and construction of five combustion turbine peaker plants, each with a capacity of approximately 45 MW and made continued progress in permitting the expansion of SCE's transmission system, which will result in the interconnection of renewable generation as well as increased transfer capacity. See "Regulatory Matters—Current Regulatory Developments—2006 General Rate Case Proceeding" and "—Peaker Plant Generation Projects" for further discussion of these matters.

- Progress toward a set of market rules that permit SCE to procure power efficiently – SCE made significant progress in 2006 to ensure that its customers have adequate energy resources available to meet their needs. SCE received CPUC approval of rules to enter into 10-year contracts for new generation projects serving its service territory, with all benefits and costs allocated across all its distribution service customers, including customers of community choice aggregators and direct access providers. SCE added significant new renewable energy contracts, including the nation's largest wind contract, and is currently in negotiations with counterparties resulting from a request for offers from renewable resources. SCE's energy portfolio currently meets all required year-ahead system and local resource adequacy requirements. SCE has also been working with a broad range of market participants on a capacity market design that would support development of sufficient resources while allocating cost responsibility fairly across all customers.

Other significant developments in 2006:

- On June 19, 2006, SCE announced that it had decided not to move forward with its efforts to return Mohave to service. SCE's decision was not based on any one factor, but resulted from the conclusion that in light of all the significant unresolved challenges related to returning the plant to service, the plant could not be returned to service in sufficient time to render the necessary investments cost-effective for SCE's customers. See "Regulatory Matters—Current Regulatory Developments—Mohave Generating Station and Related Proceedings" for further discussion.

In 2007, SCE plans to continue implementation of Edison International's strategic plan, with its primary focus on:

- Managed Growth –
  - Achieving 2007 milestones for SCE's 2007 – 2011 capital investment plan of up to $17.3 billion. The capital investment plan for 2007 and 2008 for CPUC-jurisdictional projects is consistent

with capital additions authorized by the CPUC in SCE's 2006 GRC. The capital investment plan for years 2009 through 2011 is subject to regulatory approvals. The capital investment plan includes distribution system refurbishment and expansion, advanced metering implementation, new transmission construction for reliability and renewable energy projects, San Onofre steam generator replacement, and new peaker installation. See "Liquidity—Capital Expenditures" for further discussion.

- Operational Excellence –
  - SCE has commenced an enterprise-wide project to implement a comprehensive, integrated software system to support the majority of its critical business processes during the next few years. The objective of this initiative is to improve the efficiency and effectiveness of its operations.
  - In 2007, SCE will continue to procure least-cost, best-fit power resources and execute effective hedging strategies consistent with the CPUC approved procurement plan. SCE expects to enter into contracts with new generation projects to be available by summer 2010 and continue to procure renewable resources in support of Renewable Portfolio Standard goals. SCE will also promote policies where SCE's bundled customers do not incur costs different than other load-serving entities, including improving regulatory rules governing returning Direct Access customers, and equal responsibility for renewables procurement, greenhouse gas standards, grid reliability costs, and other public policies.

LIQUIDITY

Overview

As of December 31, 2006, SCE had cash and equivalents of $83 million ($78 million of which was held by SCE's consolidated VIEs). As of December 31, 2006, long-term debt, including current maturities of long-term debt, was $5.6 billion. At December 31, 2006, SCE had a $1.7 billion five-year senior secured credit facility which supported $159 million in letters of credit, leaving $1.5 billion available under the credit facility. On February 23, 2007, SCE amended its credit facility, increasing the amount of borrowing capacity to $2.5 billion, extending the maturity to February 2012 and removing the first mortgage bond security pledge. As a result of removing the first mortgage bond security, the credit facility's pricing changed to an unsecured basis per the terms of the credit facility agreement.

SCE's 2007 estimated cash outflows consist of:

- Debt maturities of approximately $396 million, including $246 million of rate reduction notes that have a separate nonbypassable recovery mechanism approved by state legislation and CPUC decisions;
- Projected capital expenditures of $2.4 billion primarily to replace and expand distribution and transmission infrastructure and construct generation assets;
- Dividend payments to SCE's parent company. On February 22, 2007, the Board of Directors of SCE declared a $25 million dividend to be paid to Edison International;
- Fuel and procurement-related costs (see "Regulatory Matters—Current Regulatory Developments—Energy Resource Recovery Account Proceedings"); and
- General operating expenses.

SCE expects to meet its continuing obligations, including cash outflows for operating expenses, including power-procurement, through cash and equivalents on hand, operating cash flows and short-term borrowings, when necessary. Projected capital expenditures are expected to be financed through operating cash flows and the issuance of short-term and long-term debt and preferred equity.

SCE's liquidity may be affected by, among other things, matters described in "Regulatory Matters" and "Commitments and Indemnities."

Capital Expenditures

SCE is experiencing significant growth in actual and planned capital expenditures to replace and expand its distribution and transmission infrastructure, and to construct and replace generation assets. On February 22, 2007, the Finance Committee of the Board of Directors approved SCE's 2007 through 2011 capital investment plan which includes total capital spending of up to $17.3 billion. The 2007 and 2008 planned expenditures for CPUC-jurisdictional projects are consistent with capital additions authorized by the CPUC in SCE's 2006 GRC. Recovery of the 2009 through 2011 planned expenditures is subject to CPUC approval. The completion of the projects, the timing of expenditures, and the associated recovery may be affected by construction delays resulting from the availability of labor, equipment and materials, permitting requirements, financing, legal and regulatory developments, weather and other unforeseen conditions. Recovery of certain projects included in the 2007 through 2011 investment plan has been approved or will be requested through other CPUC-authorized mechanisms on a project-by-project basis. These projects include SCE's advanced metering infrastructure project, the San Onofre steam generator replacement project, and the peaker plant generation project. SCE plans total spending for 2007 through 2011 to be $1.1 billion, $500 million, and $190 million, for each project, respectively. Recovery of the 2007 through 2011 planned expenditures for FERC-jurisdictional projects will be requested in future transmission rate filings with the FERC.

The estimated capital expenditures for the five years are as follows: 2007 – $2.4 billion; 2008 – $2.8 billion; 2009 – $3.9 billion; 2010 – $4.2 billion; and 2011 – $4.0 billion. Significant investments in 2007 are expected to include:

- $1.4 billion related to transmission and distribution projects;
- $465 million related to generation projects;
- $290 million related to information technology projects, including the implementation of a comprehensive integrated software system to support a majority of SCE's critical business processes; and
- $220 million related to other customer service and shared services projects.

Credit Ratings

At December 31, 2006, SCE's credit rating on long-term senior secured debt from Standard & Poor's, Moody's Investor Service and Fitch were BBB+ and A2, and A-, respectively. At December 31, 2006, SCE's short-term (commercial paper) credit ratings from Standard & Poor's, Moody's Investor Service and Fitch were A-2, P-2, and F-1, respectively.

Dividend Restrictions and Debt Covenants

The CPUC regulates SCE's capital structure and limits the dividends it may pay Edison International. In SCE's most recent cost of capital proceeding, the CPUC set an authorized capital structure for SCE which included a common equity component of 48%. SCE determines compliance with this capital structure based on a 13-month weighted-average calculation. At December 31, 2006, SCE's 13-month weighted-average common equity component of total capitalization was 49.46%. At December 31, 2006, SCE had the capacity to pay $164 million in additional dividends based on the 13-month weighted-average method. However, based on recorded December 31, 2006 balances, SCE's common equity to total capitalization ratio (as adjusted for rate-making purposes) was 48.65%. SCE had the capacity to pay $73 million of additional dividends to Edison International based on December 31, 2006 recorded balances.

SCE has a debt covenant in its credit facility that requires a debt to total capitalization ratio of less than or equal to 0.65 to 1 to be met. At December 31, 2006, SCE's debt to total capitalization ratio was 0.45 to 1.

Margin and Collateral Deposits

SCE has entered into certain margining agreements for power and gas trading activities in support of its procurement plan as approved by the CPUC. SCE's margin deposit requirements under these agreements can vary depending upon the level of unsecured credit extended by counterparties and brokers, changes in market prices relative to contractual commitments, and other factors. At December 31, 2006, SCE had a net deposit of $154 million (consisting of $35 million in cash and reflected in "Margin and collateral deposits" on the balance sheet and $119 million in letters of credit) with counterparties. In addition, SCE has deposited $60 million (consisting of $20 million in cash and reflected in "Margin and collateral deposits" on the balance sheet and $40 million in letters of credit) with other brokers. Cash deposits with brokers and counterparties earn interest at various rates.

Margin and collateral deposits in support of power contracts and trading activities fluctuate with changes in market prices. At January 31, 2007, SCE had a net deposit of $367 million (consisting of $35 million in cash and reflected in "Margin and collateral deposits" on the balance sheet and $332 million in letters of credit) with counterparties. Future margin and collateral requirements may be higher or lower than the margin collateral requirements as of December 31, 2006 and January 31, 2007, based on future market prices and volumes of trading activity.

In addition, as discussed in "Regulatory Matters—Overview of Ratemaking Mechanisms—CDWR-Related Rates," the CDWR entered into contracts to purchase power for the sale at cost directly to SCE's retail customers during the California energy crisis. These CDWR procurement contracts contain provisions that would allow the contracts to be assigned to SCE if certain conditions are satisfied, including having an unsecured credit rating of BBB/Baa2 or higher. However, because the value of power from these CDWR contracts is subject to market rates, such an assignment to SCE, if actually undertaken, could require SCE to post significant amounts of collateral with the contract counterparties, which would strain SCE's liquidity. In addition, the requirement to take responsibility for these ongoing fixed charges, which the credit rating agencies view as debt equivalents, could adversely affect SCE's credit rating. SCE opposes any attempt to assign the CDWR contracts. However, it is possible that attempts may be made to order SCE to take assignment of these contracts, and that such orders might withstand legal challenges.

Rate Reduction Notes

In December 1997, $2.5 billion of rate reduction notes were issued on behalf of SCE by SCE Funding LLC, a special purpose entity. These notes were issued to finance the 10% rate reduction mandated by state law beginning in 1998. The proceeds of the rate reduction notes were used by SCE Funding LLC to purchase from SCE an enforceable right known as transition property. Transition property is a current property right created by the restructuring legislation and a financing order of the CPUC and consists generally of the right to be paid a specified amount from nonbypassable rates charged to residential and small commercial customers. The rate reduction notes are being repaid over 10 years through these nonbypassable residential and small commercial customer rates, which constitute the transition property purchased by SCE Funding LLC. The notes are scheduled to be paid off in December 2007 and the nonbypassable rates being charged to customers are expected to cease as of January 1, 2008. The notes are collateralized by the transition property and are not collateralized by, or payable from, assets of SCE. SCE used the proceeds from the sale of the transition property to retire debt and equity securities. Although, as required by accounting principles generally accepted in the United States of America, SCE Funding LLC is consolidated with SCE and the rate reduction notes are shown as long-term debt in the consolidated financial statements, SCE Funding LLC is legally separate from SCE. The assets of SCE Funding LLC are not available to creditors of SCE and the transition property is legally not an asset of SCE.

REGULATORY MATTERS

Overview of Ratemaking Mechanisms

SCE is an investor-owned utility company providing electricity to retail customers in central, coastal and southern California. SCE is regulated by the CPUC and the FERC. SCE bills its customers for the sale of electricity at rates authorized by these two commissions. These rates are categorized into three groups: base rates, cost-recovery rates, and CDWR-related rates.

Base Rates

Revenue arising from base rates is designed to provide SCE a reasonable opportunity to recover its costs and earn an authorized return on SCE's net investment in generation, transmission and distribution (or rate base). Base rates provide for recovery of operations and maintenance costs, capital-related carrying costs (depreciation, taxes and interest) and a return or profit, on a forecast basis.

Base rates related to SCE's generation and distribution functions are authorized by the CPUC through a GRC. In a GRC proceeding, SCE files an application with the CPUC to update its authorized annual revenue requirement. After a review process and hearings, the CPUC sets an annual revenue requirement by multiplying an authorized rate of return, determined in annual cost of capital proceedings (as discussed below), by rate base, then adding to this amount the adopted operation and maintenance costs and capital-related carrying costs. Adjustments to the revenue requirement for the remaining years of a typical three-year GRC cycle are requested from the CPUC based on criteria established in a GRC proceeding for escalation in operation and maintenance costs, changes in capital-related costs and the expected number of nuclear refueling outages. See "—Current Regulatory Developments—2006 General Rate Case Proceeding" for SCE's current annual revenue requirement. Variations in generation and distribution revenue arising from the difference between forecast and actual electricity sales are recorded in balancing accounts for future recovery or refund, and do not impact SCE's operating profit, while differences between forecast and actual operating costs, other than cost-recovery costs (see below), do impact profitability.

Base rate revenue related to SCE's transmission function is authorized by the FERC in periodic proceedings that are similar to the CPUC's GRC proceeding, except that requested rate changes are generally implemented either when the application is filed or after a maximum five month suspension. Revenue collected prior to a final FERC decision is subject to refund.

SCE's capital structure, including the authorized rate of return, is regulated by the CPUC and is determined in an annual cost of capital proceeding. The rate of return is a weighted average of the return on common equity and cost of long-term debt and preferred equity. In 2006, SCE's rate-making capital structure was 48% common equity, 43% long-term debt and 9% preferred equity. SCE's authorized cost of long-term debt was 6.17%, its authorized cost of preferred equity was 6.09% and its authorized return on common equity was 11.60%. If actual costs of long-term debt or preferred equity are higher or lower than authorized, SCE's earnings are impacted in the current year and the differences are not subject to refund or recovery in rates. See "—Current Regulatory Developments—2007 Cost of Capital Proceeding" for discussion of SCE's 2007 cost of capital proceeding.

The CPUC is currently considering a Risk/Reward Incentive Mechanism for the California investor-owned utilities based upon their energy efficiency program performance, as measured against the goals set by the CPUC, which may or may not include penalties. A decision by the CPUC is anticipated by the end of the second quarter of 2007.

Cost-Recovery Rates

Revenue requirements to recover SCE's costs of fuel, purchased power, demand-side management programs, nuclear decommissioning, rate reduction debt requirements, public purpose programs, and certain operation and maintenance expenses are authorized in various CPUC proceedings on a cost-recovery basis, with no markup for return or profit. Approximately 56% of SCE's annual revenue relates to the recovery of these costs. Although the CPUC authorizes balancing account mechanisms to refund or recover any differences between estimated and actual costs, under- or over-collections in these balancing accounts can build rapidly due to fluctuating prices (particularly for purchased power) and can greatly impact cash flows. SCE may request adjustments to recover or refund any under- or over-collections. The majority of costs eligible for recovery are subject to CPUC reasonableness reviews, and thus could negatively impact earnings and cash flows if found to be unreasonable and disallowed.

CDWR-Related Rates

As a result of the California energy crisis, in 2001 the CDWR entered into contracts to purchase power for sale at cost directly to SCE's retail customers and issued bonds to finance those power purchases. The CDWR's total statewide power charge and bond charge revenue requirements are allocated by the CPUC among the customers of SCE, PG&E and SDG&E (collectively, the investor-owned utilities). SCE bills and collects from its customers the costs of power purchased and sold by the CDWR, CDWR bond-related charges and direct access exit fees. The CDWR-related charges and a portion of direct access exit fees (approximately $2.5 billion was collected in 2006) are remitted directly to the CDWR and are not recognized as revenue by SCE and therefore have no impact on SCE's earnings; however they do impact customer rates.

Impact of Regulatory Matters on Customer Rates

SCE is concerned about high customer rates, which were a contributing factor that led to the deregulation of the electric services industry during the mid-1990s. The following table summarizes SCE's system average rates at various dates in 2006 in which rate changes were implemented:

Date	SCE System Average Rate
January 1, 2006	13.7¢
February 4, 2006	14.3¢
June 4, 2006	14.5¢
August 1, 2006	14.7¢
October 1, 2006	14.8¢

The rate changes implemented during 2006 primarily related to the implementation of SCE's 2006 ERRA forecast, implementation of the 2006 GRC decision and modification of the FERC transmission-related rates. To mitigate the impact of the August 1, 2006 rate increase on residential customers during a period of record heat conditions in Southern California, the CPUC granted SCE's request to defer the residential rate increase to November 1, 2006, and subsequently approved the deferral to January 1, 2007. The CPUC also approved a mechanism in which SCE will collect the authorized revenue earned during this deferral period over a 12-month period beginning January 1, 2007. Under regulatory accounting, SCE is entitled to recognize revenue based on amounts authorized. As a result, the revenue associated with the residential rate increase is recognized as earned; however, collection is being deferred until January 1, 2007.

On February 14, 2007 SCE's system average rate decreased to 13.9¢-per-kWh mainly as the result of estimated lower gas prices in 2007, as well as the refund of ERRA overcollections that occurred in 2006 from lower than expected gas prices and higher than expected kWh sales (see "—Current Regulatory Developments—Energy Resource Recovery Account Proceedings").

Current Regulatory Developments

This section of the MD&A describes significant regulatory issues that may impact SCE's financial condition or results of operation.

2006 General Rate Case Proceeding

On May 11, 2006, the CPUC issued its final decision in SCE's 2006 GRC authorizing an increase of $274 million over SCE's 2005 base rate revenue, retroactive to January 12, 2006. When the one-time credit of $140 million from an existing balancing account overcollection was applied, SCE's authorized increase was $134 million. The CPUC also authorized increases of $74 million in 2007 and $104 million in 2008. The decision substantially approved SCE's request to continue its capital investment program for infrastructure replacement and expansion, with authorized revenue in excess of costs for this program subject to refund. In addition, the decision provided for balancing accounts for pensions, postretirement medical benefits and certain incentive compensation expense.

During the second quarter of 2006, SCE implemented the 2006 GRC decision and resolved an outstanding regulatory issue which resulted in a pre-tax benefit of approximately $175 million. The implementation of the 2006 GRC decision retroactive to January 12, 2006 mainly resulted in revenue of $50 million related to the revenue requirement for the period January 12, 2006 through May 31, 2006, partially offset by the implementation of the new depreciation rates resulting in increased depreciation expense of approximately $25 million for the period January 12, 2006 through May 31, 2006. In addition, there was a favorable resolution of a one-time issue related to a portion of revenue collected during the 2001–2003 period for state income taxes. SCE was able to determine through regulatory proceedings, including the 2006 GRC decision, that the level of revenue collected during that period was appropriate, and as a result recorded a pre-tax gain of $135 million (reflected in the caption "Provisions for regulatory adjustments clauses—net" on the income statement). See "Regulatory Matters—Impact of Regulatory Matters on Customer Rates" for further discussion.

2006 Cost of Capital Proceeding

On December 15, 2005, the CPUC granted SCE's requested rate-making capital structure of 43% long-term debt, 9% preferred equity and 48% common equity for 2006. The CPUC also authorized SCE's 2006 cost of long-term debt of 6.17%, cost of preferred equity of 6.09% and a return on common equity of 11.60%. The CPUC decision resulted in a $23 million decrease in SCE's annual revenue requirement due to lower interest costs partially offset by an increase in return on common equity.

2007 Cost of Capital Proceeding

On March 27, 2006, SCE initiated proceedings requesting the CPUC to waive the requirement that SCE file a 2007 cost of capital application and instead file its next application in 2007 for year 2008. On August 24, 2006, the CPUC issued a final decision granting SCE's waiver application and, as a result, SCE's authorized capital structure, return on common equity of 11.60% and overall rate of return on capital of 8.77%, will not change for 2007.

2006 FERC Rate Case

SCE's electric transmission revenue and wholesale and retail transmission rates are subject to authorization by the FERC. On November 10, 2005, SCE filed proposed revisions to the 2006 base transmission rates, which would have increased SCE's revenue requirement by $65 million, or 23%, over 2006 base transmission rates (which were authorized in 2003) and requested an effective date of January 10, 2006. On May 30, 2006, the FERC authorized an effective date for the new rates of June 4, 2006. SCE's request for rehearing on the effective date issue was subsequently denied. On July 6, 2006, the FERC approved a settlement that set a revenue requirement of $312 million, which increased SCE's revenue requirement by $26 million over 2006 base transmission rates. See "Regulatory Matters—Impact of Regulatory Matters on Customer Rates."

Energy Resource Recovery Account Proceedings

The ERRA is the balancing account mechanism to track and recover SCE's fuel and procurement-related costs. As described in "—Overview of Ratemaking Mechanisms," SCE recovers these costs on a cost-recovery basis, with no mark-up for return or profit. SCE files annual forecasts of the above-described costs that it expects to incur during the following year. These costs are tracked and recovered in customer rates through the ERRA, as incurred, but are subject to a reasonableness review in a separate annual ERRA application. If the ERRA balancing account incurs an overcollection or undercollection in excess of 4% of SCE's prior year's generation revenue, the CPUC has established a "trigger" mechanism, whereby SCE must file an application in which it can request an emergency rate adjustment if the ERRA overcollection or undercollection exceeds 5% of SCE's prior year's generation revenue.

On September 1, 2006, SCE filed an ERRA trigger application, as a result of a July 2006 overcollection position, proposing that no further rate action be taken and to allow SCE to maintain its currently authorized ERRA rates for the remainder of 2006 until other rate changes, including the 2007 ERRA revenue requirement, were implemented in 2007. As a result, at December 31, 2006, the ERRA was overcollected by $526 million, which was 13.2% of SCE's prior year's generation revenue. On January 25, 2007, the CPUC approved SCE's request to reduce the 2007 ERRA revenue requirement by $630 million, which included the overcollection in the ERRA balancing account. The CPUC also authorized SCE to consolidate the ERRA proceeding revenue requirement with the authorized revenue requirement changes in other SCE proceedings to be implemented in 2007. SCE forecasts that the ERRA overcollection at December 2006 will begin to decrease as the overcollection is returned to customers through lower generation rate levels implemented in February 2007. See "Regulatory Matters—Impact of Regulatory Matters on Customer Rates" for further discussion.

Resource Adequacy Requirements

Under the CPUC's resource adequacy framework, all load-serving entities in California have an obligation to procure sufficient resources to meet their expected customers' needs on a system-wide basis with a 15–17% reserve level. In addition, on June 6, 2006, the CPUC adopted local resource adequacy requirements.

Effective February 16, 2006, SCE was required to demonstrate that it had procured sufficient resources to meet 90% of its June–September 2006 system resource adequacy requirement. Beginning in May 2006, SCE is required to demonstrate every month that it has met 100% of its system resource adequacy requirement one month in advance of expected need. SCE made a showing of compliance with its system resource adequacy requirements in each of its monthly compliance filings for May through December 2006. SCE made a showing of compliance with its year-ahead system resource adequacy requirements for 2007 on November 2, 2006. SCE expects to make a showing of compliance with its system resource adequacy requirements in each of its monthly compliance filings for 2007. The system resource adequacy requirements provide for penalties of 150% of the cost of new monthly capacity for failing to meet the system resource adequacy requirements in 2006, and a 300% penalty in 2007 and beyond.

Under the local resource adequacy requirements, SCE must demonstrate that it has procured 100% of its requirement within defined local areas. The local resource adequacy requirements provide for penalties of 100% of the cost of new monthly capacity for failing to meet the local resource adequacy requirements. During the third quarter of 2006, the CPUC established the amount of local capacity necessary for SCE to meet its local resource adequacy requirements. SCE made a showing of compliance with its local resource adequacy requirements for 2007 on November 2, 2006.

Peaker Plant Generation Projects

On August 15, 2006, the CPUC issued a ruling addressing electric reliability needs in Southern California for the summer of 2007 and directing, among other things, that SCE pursue new utility-owned peaker generation (which would be available on notice during peak demand periods) that would be online by August 2007. SCE is currently pursuing the permitting and construction of five combustion turbine peaker plants, each with a capacity of approximately 45 MW. SCE has initially budgeted $250 million for these projects, and as of year-end 2006 had spent or firmly committed approximately $95 million. In November 2006, the CPUC authorized SCE to establish a new memorandum account and revise its existing Base Revenue Requirement Balancing Account, to enable SCE to commence recording the revenue requirement associated with each peaker as soon as each peaker begins operations. After the peaker plants are operating and before December 31, 2007, SCE will be required to submit a review application to determine the reasonableness of the costs. If the CPUC finds any of the costs to be unreasonable, appropriate rate adjustments will be made.

Procurement of Renewable Resources

California law requires SCE to increase its procurement of renewable resources by at least 1% of its annual retail electricity sales per year so that 20% of its annual electricity sales are procured from renewable resources by no later than December 31, 2010.

SCE entered into a contract with Calpine Energy Services, L.P. to purchase the output of certain existing geothermal facilities in northern California. Under previous CPUC decisions and reporting and compliance methodology, SCE was only able to count procurement pursuant to the Calpine contract towards its annual renewable target to the extent the output was certified as "incremental" by the CEC. On October 19, 2006, the CPUC issued a decision that revised the reporting and compliance methodology, and permitted SCE to count the entire output under the Calpine contract towards satisfaction of its annual renewable procurement target thus meeting its renewable procurement objectives for 2003, 2004, 2005 and 2006. The decision also implemented a "cumulative deficit banking" feature which would carry forward and accumulate annual deficits until the deficit has been satisfied at a later time through actual deliveries of eligible renewable energy.

Under the new methodology, SCE could have deficits in meeting its renewable procurement obligations for 2007 and beyond. However, based on California law, SCE has challenged the CPUC's accounting determination that defines the annual targets for each year of the renewable portfolio standards program. A change in the CPUC's accounting methodology in response to this challenge would enable SCE to meet its target for 2007 and possibly later years. At this time, SCE cannot predict the outcome of its challenge. Regardless of the CPUC's decision on SCE's challenge, SCE believes it may be able to demonstrate that it should not be penalized for any deficit.

Under current CPUC decisions, potential penalties for SCE's failure to achieve its renewable procurement objectives for any year will be considered by the CPUC in the context of the CPUC's review of SCE's annual compliance filing. Under the CPUC's current rules, the maximum penalty for failing to achieve renewable procurement targets is $25 million per year. SCE cannot predict whether it will be assessed penalties.

Request for Offers from Renewable Resources

SCE is engaged in several initiatives to procure renewable resources, including formal solicitations approved by the CPUC, bilateral negotiations with individual projects and other initiatives. On July 14, 2006, SCE requested proposals for power purchase contracts from renewable energy resource and received bids in September 2006. SCE has reviewed these bids and has begun negotiations with bidders in an attempt to enter into final contracts. The contract lengths will be from 10 to 20 years. In addition, in November and December 2006, SCE executed several renewable power purchase contracts, subject to CPUC approval, originating from its 2005 solicitation.

Mohave Generating Station and Related Proceedings

Mohave obtained all of its coal supply from the Black Mesa Mine in northeast Arizona, located on lands of the Tribes. This coal was delivered from the mine to Mohave by means of a coal slurry pipeline, which required water from wells located on lands belonging to the Tribes in the mine vicinity. Uncertainty over post-2005 coal and water supply has prevented SCE and other Mohave co-owners from making approximately $1.1 billion in Mohave-related investments (SCE's share is $605 million), including the installation of enhanced pollution-control equipment required by a 1999 air-quality consent decree in order for Mohave to operate beyond 2005. Accordingly, the plant ceased operations, as scheduled, on December 31, 2005, consistent with the provisions of the consent decree.

On June 19, 2006, SCE announced that it had decided not to move forward with its efforts to return Mohave to service. SCE's decision was not based on any one factor, but resulted from the conclusion that in light of all the significant unresolved challenges related to returning the plant to service, the plant could not be returned to service in sufficient time to render the necessary investments cost-effective for SCE's customers. Two of the other Mohave co-owners, Nevada Power Company and the DWP, made similar announcements, while the fourth co-owner, SRP, initially announced that it was pursuing the possibility of putting together a successor owner group, which would include SRP, to pursue continued coal operations. On February 6, 2007, however, SRP issued a press release announcing that it was discontinuing its efforts to return Mohave to service. All of the co-owners are continuing to evaluate the range of options for disposition of the plant, which conceivably could include, among other potential options, sale of the plant "as is" to a power plant operator, decommissioning and sale of the property to a developer, and decommissioning and apportionment of the land among the owners. At this time, SCE continues to work with the water and coal suppliers to the plant to determine if more clarity around the provision of such services can be provided to any potential acquirer.

Following the suspension of Mohave operations at the end of 2005, the plant's workforce was reduced from over 300 employees to 65 employees by the end of 2006. SCE recorded $15 million in termination costs during the year for Mohave (SCE's share). These termination costs were deferred in a balancing account authorized in the 2006 GRC decision. SCE expects to recover this amount in the balancing account in future rate-making proceedings.

As of December 31, 2006, SCE had a Mohave net regulatory asset of approximately $81 million representing its net unamortized coal plant investment, partially offset by revenue collected for future removal costs. Based on the 2006 GRC decision, SCE is allowed to continue to earn its authorized rate of return on the Mohave investment and receive rate recovery for amortization, costs of removal, and operating and maintenance expenses, subject to balancing account treatment, during the three-year 2006 rate case cycle. On October 5, 2006, SCE submitted a formal notification to the CPUC regarding the out-of-service status of Mohave, pursuant to a California statute requiring such notice to the CPUC whenever a plant has been out of service for nine consecutive months. SCE also reported to the CPUC on Mohave's status numerous times previously. Pursuant to the statute, the CPUC may institute an investigation to determine whether to reduce SCE's rates in light of Mohave's changed status. At this time, SCE does not anticipate that the CPUC will order a rate reduction. In the past, the CPUC has allowed full recovery of investment for similarly situated plants. However, in a December 2004 decision, the CPUC noted that SCE would not be allowed to recover any unamortized plant balances if SCE could not demonstrate that it took all steps to preserve the "Mohave-open" alternative. SCE believes that it will be able to demonstrate that SCE did everything reasonably possible to return Mohave to service, which it further believes would permit its unamortized costs to be recovered in future rates. However, SCE cannot predict the outcome of any future CPUC action.

San Onofre Nuclear Generating Station Steam Generators and Changes in Ownership

On December 15, 2005, the CPUC issued a final decision on SCE's application for replacement of SCE's San Onofre Units 2 and 3 steam generators. In that decision, the CPUC found that: (1) steam generator replacement is cost-effective; (2) SCE's estimate of the total cost of steam generator replacement of $680 million ($569 million for replacement steam generator installation and $111 million for removal and disposal of the original steam generators) is reasonable; (3) SCE will be able to recover all of its incurred costs and the CPUC does not intend to conduct an after-the-fact reasonableness review if the project is completed at a cost that does not exceed $680 million as adjusted for inflation and AFUDC; (4) a reasonableness review will be required if the project is completed at a cost between $680 million and $782 million or the CPUC later finds that it had reason to believe the costs may be unreasonable regardless of the amount; and (5) if the cost of the project exceeds $782 million, no rate recovery will be allowed for costs above $782 million as adjusted for inflation and AFUDC. On November 30, 2006, the CPUC issued a decision affirming the cost effectiveness of the steam generator replacement project and ending the rehearing of this matter.

The city of Anaheim opted out of the steam generator replacement project and agreed to transfer its 3.16% share of San Onofre to SCE. SCE received authority to acquire Anaheim's share from the FERC in April 2006 and from the NRC in September 2006. On November 30, 2006, the CPUC granted SCE authority to recover Anaheim's share of San Onofre operating and decommissioning costs. On December 29, 2006, SCE acquired Anaheim's share of San Onofre Units 2 and 3.

On November 30, 2006, the CPUC issued a decision authorizing SDG&E to participate in the steam generator replacement and to retain its 20% share of San Onofre. SDG&E immediately informed SCE of its acceptance of the CPUC's decision, and paid its share of the steam generator replacement project costs through the date of the decision.

Palo Verde Nuclear Generating Station Steam Generators

SCE owns a 15.8% interest in the Palo Verde. During 2003, the Palo Verde Unit 2 steam generators were replaced. During 2005, the Palo Verde Unit 1 steam generators were replaced. In addition, the Palo Verde owners have approved the manufacture and installation of steam generators in Unit 3. SCE expects that replacement steam generators will be installed in Unit 3 by the end of 2007. SCE's share of the costs of manufacturing and installing all of the replacement steam generators at Palo Verde is estimated to be approximately $115 million. The CPUC approved the replacement costs for Unit 2 in the 2003 GRC. The final decision in the 2006 GRC proceeding authorized SCE to recover the replacement costs for Units 1 and 3.

ISO Disputed Charges

On April 20, 2004, the FERC issued an order concerning a dispute between the ISO and the Cities of Anaheim, Azusa, Banning, Colton and Riverside, California over the proper allocation and characterization of certain transmission service related charges. The order reversed an arbitrator's award that had affirmed the ISO's characterization in May 2000 of the charges as Intra-Zonal Congestion costs and allocation of those charges to scheduling coordinators in the affected zone within the ISO transmission grid. The April 20, 2004 order directed the ISO to shift the costs from scheduling coordinators in the affected zone to the responsible participating transmission owner, SCE. The potential cost to SCE, net of amounts SCE expects to receive through the PX, SCE's scheduling coordinator at the time, is estimated to be approximately $20 million to $25 million, including interest. On April 20, 2005, the FERC stayed its April 20, 2004 order during the pendency of SCE's appeal filed with the Court of Appeals for the D.C. Circuit. On March 7, 2006, the Court of Appeals remanded the case back to the FERC at the FERC's request and with SCE's consent. A decision is expected by March 2007. The FERC may require SCE to pay these costs, but SCE does not believe this outcome is probable. If SCE is required to pay these costs, SCE may seek recovery in its reliability service rates.

Scheduling Coordinator Tariff Dispute

Pursuant to the Amended and Restated Exchange Agreement, SCE serves as a scheduling coordinator for the DWP over the ISO-controlled grid. In late 2003, SCE began charging the DWP under a tariff subject to refund for FERC-authorized scheduling coordinator charges incurred by SCE on the DWP's behalf. The scheduling coordinator charges are billed to the DWP under a FERC tariff that remains subject to dispute. The DWP has paid the amounts billed under protest but requested that the FERC declare that SCE was obligated to serve as the DWP's scheduling coordinator without charge. The FERC accepted SCE's tariff for filing, but held that the rates charged to the DWP have not been shown to be just and reasonable and thus made them subject to refund and further review by the FERC. As a result, SCE could be required to refund all or part of the amounts collected from the DWP under the tariff. As of December 31, 2006, SCE has accrued a $41 million charge to earnings for the potential refunds. SCE and DWP have entered into a term sheet that would settle this dispute, among others surrounding the Exchange Agreement. If the settlement is effectuated, SCE would refund to DWP the scheduling coordinator charges collected, with an offset for losses, subject to being able to recover the scheduling coordinator charges from all transmission grid customers through another regulatory mechanism. The parties are currently negotiating the exact terms of the settlement.

FERC Refund Proceedings

SCE is participating in several related proceedings seeking recovery of refunds from sellers of electricity and natural gas who manipulated the electric and natural gas markets during the energy crisis in California in 2000 – 2001 or who benefited from the manipulation by receiving inflated market prices. SCE is required to refund to customers 90% of any refunds actually realized by SCE, net of litigation costs, and 10% will be retained by SCE as a shareholder incentive.

During the course of the refund proceedings, the FERC ruled that governmental power sellers, like private generators and marketers that sold into the California market, should refund the excessive prices they received during the crisis period. However, on September 21, 2005, the Ninth Circuit ruled that the FERC does not have authority directly to enforce its refund orders against governmental power sellers. The Court, however, clarified that its decision does not preclude SCE or other parties from pursuing civil claims against the governmental power sellers. On March 16, 2006, SCE, PG&E and the California Electricity Oversight Board jointly filed suit in federal court against several governmental power sellers, seeking refunds based on the reduced prices set by the FERC for transactions during the crisis period. SCE cannot predict whether it may be able to recover any additional refunds from governmental power sellers as a result of this suit.

In November 2005, SCE and other parties entered into a settlement agreement with Enron Corporation and a number of its affiliates, most of which are debtors in Chapter 11 bankruptcy proceedings pending in New York. In April 2006, SCE received a distribution on its allowed bankruptcy claim of approximately $29 million, and 196,245 shares of common stock of Portland General Electric Company with an aggregate value of approximately $5 million. In October 2006, SCE received another distribution on its allowed bankruptcy claim of approximately $20 million and 17,040 shares of Portland General Electric Company stock, with an aggregate value of less than $1 million. Additional distributions are expected but SCE cannot currently predict the amount or timing of such distributions.

In December 2005, the FERC approved a settlement agreement among SCE, PG&E, SDG&E, several governmental entities and certain other parties, and Reliant Energy, Inc. and a number of its affiliates. In March 2006, SCE received $61 million as part of the consideration allocated to it under the settlement.

On August 2, 2006, the Ninth Circuit issued an opinion regarding the scope of refunds issued by the FERC. The Ninth Circuit broadened the time period during which refunds could be ordered to include the summer of 2000 based on evidence of pervasive tariff violations and broadened the categories of transactions that could be subject to refund. As a result of this decision, SCE may be able to recover additional refunds from sellers of electricity during the crisis with whom settlements have not been reached.

Holding Company Order Instituting Rulemaking

On October 27, 2005, the CPUC issued an Order Instituting Rulemaking to allow the CPUC to re-examine the relationships of the major California energy utilities with their parent holding companies and nonregulated affiliates.

On December 14, 2006, the CPUC issued a decision. From the perspectives of SCE and Edison International, the most significant provisions of this decision were: (1) changes to the "shared services" affiliate transaction rule, such that SCE must elect either to continue to share regulatory affairs, lobbying and legal services with its affiliates, or to share certain "key" officers with the holding company, including the Chairperson, CEO, President, CFO and the chief regulatory officer; (2) "key" officers (as listed in the preceding item) must personally certify annually that they have complied with the affiliate transaction rules and have no knowledge of any unreported violations; (3) the utility must obtain a nonconsolidation opinion from outside counsel demonstrating that the existing ring-fencing around the utility is sufficient to prevent the utility from being drawn into a bankruptcy of its parent holding company; (4) the utility must file a waiver application if an adverse financial event reduces the utility's actual equity ratio by more than one percent or more below the approved ratio; (5) the utility must file an annual report on utility capital needs and related financial practices; and (6) changes to the executive compensation reporting rules to increase disclosure obligations and certify that compensation has been accurately reported. It is not expected that there will be any further developments in this proceeding.

Investigations Regarding Performance Incentives Rewards

SCE was eligible under its CPUC-approved PBR mechanism to earn rewards or penalties based on its performance in comparison to CPUC-approved standards of customer satisfaction, employee injury and illness reporting, and system reliability.

SCE conducted investigations into its performance under these PBR mechanisms and has reported to the CPUC certain findings of misconduct and misreporting as further discussed below.

Customer Satisfaction

SCE received two letters in 2003 from one or more anonymous employees alleging that personnel in the service planning group of SCE's transmission and distribution business unit altered or omitted data in attempts to influence the outcome of customer satisfaction surveys conducted by an independent survey organization. The results of these surveys are used, along with other factors, to determine the amounts of any incentive rewards or penalties for customer satisfaction. SCE recorded aggregate customer satisfaction rewards of $28 million over the period 1997–2000. Potential customer satisfaction rewards aggregating $10 million for the years 2001 and 2002 are pending before the CPUC and have not been recognized in income by SCE. SCE also anticipated that it could be eligible for customer satisfaction rewards of approximately $10 million for 2003.

Following its internal investigation, SCE proposed to refund to ratepayers $7 million of the PBR rewards previously received and forgo an additional $5 million of the PBR rewards pending that are both attributable to the design organization's portion of the customer satisfaction rewards for the entire PBR period (1997–2003). In addition, SCE also proposed to refund all of the approximately $2 million of customer satisfaction rewards associated with meter reading.

SCE has taken remedial action as to the customer satisfaction survey misconduct by disciplining employees and/or terminating certain employees, including several supervisory personnel, updating system process and related documentation for survey reporting, and implementing additional supervisory controls over data collection and processing. Performance incentive rewards for customer satisfaction expired in 2003 pursuant to the 2003 GRC.

Employee Injury and Illness Reporting

In light of the problems uncovered with the customer satisfaction surveys, SCE conducted an investigation into the accuracy of SCE's employee injury and illness reporting. The yearly results of employee injury and illness reporting to the CPUC are used to determine the amount of the incentive reward or penalty to SCE under the PBR mechanism. Since the inception of PBR in 1997, SCE has recognized $20 million in employee safety incentives for 1997 through 2000 and, based on SCE's records, may be entitled to an additional $15 million for 2001 through 2003.

On October 21, 2004, SCE reported to the CPUC and other appropriate regulatory agencies certain findings concerning SCE's performance under the PBR incentive mechanism for injury and illness reporting. SCE disclosed in the investigative findings to the CPUC that SCE failed to implement an effective recordkeeping system sufficient to capture all required data for first aid incidents.

As a result of these findings, SCE proposed to the CPUC that it not collect any reward under the mechanism and return to ratepayers the $20 million it has already received. SCE has also proposed to withdraw the pending rewards for the 2001 – 2003 time frames.

SCE has taken remedial action to address the issues identified, including revising its organizational structure and overall program for environmental, health and safety compliance, disciplining employees who committed wrongdoing and terminating one employee. SCE submitted a report on the results of its investigation to the CPUC on December 3, 2004.

System Reliability

In light of the problems uncovered with the PBR mechanisms discussed above, SCE conducted an investigation into the third PBR metric, system reliability. On February 28, 2005, SCE provided its final investigatory report to the CPUC concluding that the reliability reporting system is working as intended.

CPUC Investigation

On June 15, 2006, the CPUC instituted a formal investigation to determine whether and in what amounts to order refunds or disallowances of past and potential PBR rewards for customer satisfaction, employee safety, and system reliability portions of PBR. The CPUC also may consider whether to impose additional penalties on SCE.

In June 2006, the CPSD of the CPUC issued its report regarding SCE's PBR program, recommending that the CPUC impose various refunds and penalties on SCE. Subsequently, in September 2006, the CPSD and other intervenors, such as the CPUC's Division of Ratepayer Advocates and The Utility Reform Network filed testimony on these matters recommending various refunds and penalties to be imposed upon SCE. On October 16, 2006, SCE filed testimony opposing the various refund and penalty recommendations of the CPSD and other intervenors. Based on SCE's proposal for refunds and the combined recommendations of the CPSD and other intervenors, the potential refunds and penalties could range from $52 million up to $388 million. SCE has recorded an accrual at the lower end of this range of potential loss and is accruing interest on collected amounts that SCE has proposed to refund to customers. Evidentiary hearings which addressed the planning and meter reading components of customer satisfaction, safety, issues related to SCE's administration of the survey, and statutory fines associated with those matters took place in the fourth quarter of 2006. A schedule has not been set to address the other components of customer satisfaction, system reliability, and other issues in a second phase of the proceeding, although the CPSD has indicated its intent to complete a report by August 2007. A Presiding Officer's Decision is expected during the second quarter of 2007 on the issues addressed during phase one. At this time, SCE cannot predict the outcome of these matters or reasonably estimate the potential amount of any additional refunds, disallowances, or penalties that may be required above the lower end of the range.

Settlement Agreement with Duke Energy Trading and Marketing, LLC

On September 21, 2006, the CPUC approved a settlement agreement between SCE and Duke that resolved disputes arising from Duke's termination of certain bilateral power supply contracts in early 2001. Under the settlement, Duke made a $77 million principal and interest payment to SCE in October 2006, which will be refunded to ratepayers through the ERRA mechanism. The settlement also permitted $58 million in liabilities that SCE had previously recorded with respect to the Duke terminated contracts to be reversed, which resulted in an equivalent benefit recorded by SCE in the third quarter of 2006 (reflected in the caption "Purchased power" on the income statement). The CPUC agreed that these liabilities should not be refunded to ratepayers. The recorded liabilities consisted of $40 million in cash collateral received from Duke in 2000 and $18 million in power purchase payments that SCE, in light of Duke's termination of the bilateral contracts, withheld for energy delivered by Duke in January 2001.

OTHER DEVELOPMENTS

Environmental Matters

SCE is subject to numerous federal and state environmental laws and regulations, which require it to incur substantial costs to operate existing facilities, construct and operate new facilities, and mitigate or remove the effect of past operations on the environment. SCE believes that its operating affiliates are in substantial compliance with existing environmental regulatory requirements.

SCE's power plants, in particular its coal-fired plants, may be affected by recent developments in federal and state environmental laws and regulations. These laws and regulations, including those relating to SO_2 and NO_x emissions, mercury emissions, ozone and fine particulate matter emissions, regional haze, water quality, and climate change, may require significant capital expenditures at these facilities. The developments in certain of these laws and regulations are discussed in more detail below. These developments will continue to be monitored to assess what implications, if any, they will have on the operation of domestic power plants owned or operated by SCE, or the impact on SCE's results of operations or financial position.

SCE's projected environmental capital expenditures over the next five years are: 2007 – $414 million; 2008 – $423 million; 2009 – $419 million; 2010 – $423 million; and 2011 – $423 million. The projected environmental capital expenditures are mainly for undergrounding certain transmission and distribution lines.

Air Quality Standards

Suspension of Mohave Operations and SCE Decision to Discontinue Its Participation in Efforts to Resume Operations

In 1998, several environmental groups filed suit against the co-owners of Mohave regarding alleged violations of emissions limits. In order to resolve the lawsuit and accelerate resolution of key environmental issues regarding the plant, the parties entered into a consent decree, which was approved by the Nevada federal district court in December 1999. The consent decree required the installation of certain air pollution control equipment prior to December 31, 2005 if the plant was to operate beyond that date. In addition, operation beyond 2005 required, among other things, that agreements be reached with the Tribes regarding post-2005 water and coal supply needs. Without the prior resolution of the post-2005 water and coal supply issues, the Mohave owners did not proceed with the major expenditures necessary for the pollution controls and other investments necessary for long-term operation of Mohave beyond 2005.

Agreement with the Tribes on water and coal supplies for Mohave was not reached by December 31, 2005. Efforts to modify the terms of the federal court consent decree to allow Mohave to continue operating for an interim period without the required pollution controls, pending resolution of water and coal issues, also were unsuccessful. As a result, Mohave suspended all generation operations on December 31, 2005.

On June 19, 2006, SCE announced that for numerous reasons it had decided not to move forward with its efforts to return Mohave to service. Additional information regarding Mohave appears in the MD&A under the heading "Regulatory Matters—Mohave Generating Station and Related Proceedings."

Climate Change

In April 2006, private citizens brought a complaint in federal court in Mississippi against numerous defendants, including several electric utilities, arguing that emissions from the defendants' facilities contributed to climate change and seeking monetary damages related to the 2005 hurricane season. On December 19, 2006, the plaintiffs sought permission from the court to file an amended complaint naming approximately one hundred new defendants, including SCE. The court has not yet ruled on the plaintiffs' motion.

In September 2006, California's Governor Schwarzenegger signed two bills into law regarding GHG emissions. The first, known as AB 32 or the California Global Warming Solutions Act of 2006, establishes a comprehensive program of regulatory and market mechanisms to achieve reductions of GHGs. AB 32 requires the California Air Resources Board to develop regulations and market mechanisms targeted to reduce California's greenhouse gas emissions to 1990 levels by 2020. California Air Resources Board's mandatory program will take effect commencing 2012 and will implement incremental reductions so that greenhouse gas emissions will be reduced to 1990 levels by 2020. The second bill, known as SB 1368, relates specifically to power generation and requires the CPUC and the CEC to adopt GHG performance standards for investor owned and publicly owned utilities, respectively, for long-term procurement of electricity. The standards must equal the performance of a combined-cycle gas turbine generator. The CPUC adopted such a standard on January 25, 2007 (which limits emissions to 1,100 pounds of carbon dioxide per MWh). The CEC must take similar action by June 30, 2007. In addition, the CPUC is addressing climate change related issues in various regulatory proceedings. SCE will continue to monitor the federal and state developments relating to regulation of GHG emissions to determine their impacts on SCE's operations. Requirements to reduce emissions of CO_2 and other GHGs could significantly increase SCE's cost of generating electricity from fossil fuels, especially coal, as well as the cost of purchased power, which are generally borne by SCE's customers.

Environmental Remediation

SCE records its environmental remediation liabilities when site assessments and/or remedial actions are probable and a range of reasonably likely cleanup costs can be estimated. SCE reviews its sites and measures the liability quarterly, by assessing a range of reasonably likely costs for each identified site using currently available information, including existing technology, presently enacted laws and regulations, experience gained at similar sites, and the probable level of involvement and financial condition of other potentially responsible parties. These estimates include costs for site investigations, remediation, operations and maintenance, monitoring and site closure. Unless there is a probable amount, SCE records the lower end of this reasonably likely range of costs (classified as other long-term liabilities) at undiscounted amounts.

SCE's recorded estimated minimum liability to remediate its 23 identified sites is $78 million. The ultimate costs to clean up SCE's identified sites may vary from its recorded liability due to numerous uncertainties inherent in the estimation process, such as: the extent and nature of contamination; the scarcity of reliable data for identified sites; the varying costs of alternative cleanup methods;

developments resulting from investigatory studies; the possibility of identifying additional sites; and the time periods over which site remediation is expected to occur. SCE believes that, due to these uncertainties, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $123 million. The upper limit of this range of costs was estimated using assumptions least favorable to SCE among a range of reasonably possible outcomes. In addition to its identified sites (sites in which the upper end of the range of costs is at least $1 million), SCE also has 32 immaterial sites whose total liability ranges from $3 million (the recorded minimum liability) to $8 million.

The CPUC allows SCE to recover environmental remediation costs at certain sites, representing $31 million of its recorded liability, through an incentive mechanism (SCE may request to include additional sites). Under this mechanism, SCE will recover 90% of cleanup costs through customer rates; shareholders fund the remaining 10%, with the opportunity to recover these costs from insurance carriers and other third parties. SCE has successfully settled insurance claims with all responsible carriers. SCE expects to recover costs incurred at its remaining sites through customer rates. SCE has recorded a regulatory asset of $77 million for its estimated minimum environmental-cleanup costs expected to be recovered through customer rates.

SCE's identified sites include several sites for which there is a lack of currently available information, including the nature and magnitude of contamination and the extent, if any, that SCE may be held responsible for contributing to any costs incurred for remediating these sites. Thus, no reasonable estimate of cleanup costs can be made for these sites.

SCE expects to clean up its identified sites over a period of up to 30 years. Remediation costs in each of the next several years are expected to range from $11 million to $25 million. Recorded costs for the year ended December 31, 2006 were $14 million.

Based on currently available information, SCE believes it is unlikely that it will incur amounts in excess of the upper limit of the estimated range for its identified sites and, based upon the CPUC's regulatory treatment of environmental remediation costs, SCE believes that costs ultimately recorded will not materially affect its results of operations or financial position. There can be no assurance, however, that future developments, including additional information about existing sites or the identification of new sites, will not require material revisions to such estimates.

Enterprise-Wide Software System Project

SCE has commenced an enterprise-wide project to implement a comprehensive, integrated software system to support the majority of its critical business processes during the next few years. The objective of this initiative is to improve the efficiency and effectiveness of its operations and enhance the transparency of information.

Federal and State Income Taxes

Edison International received Revenue Agent Reports from the IRS in August 2002 and in January 2005 asserting deficiencies in federal corporate income taxes with respect to audits of its 1994–1996 and 1997–1999 tax years, respectively. Many of the asserted tax deficiencies are timing differences and, therefore, amounts ultimately paid (exclusive of penalties), if any, would benefit SCE as future tax deductions. Edison International has also submitted affirmative claims to the IRS and state tax agencies which are being addressed in administrative proceedings. Any benefits would be recorded at the earlier of when Edison International believes that the affirmative claim position has a more likely than not probability of being sustained or when a settlement is reached. Certain affirmative claims may be recorded as part of the implementation of FIN 48.

The IRS Revenue Agent Report for the 1997–1999 audit also asserted deficiencies with respect to a transaction entered into by an SCE subsidiary which may be considered substantially similar to a listed transaction described by the IRS as a contingent liability company. While Edison International and SCE intend to defend their tax return position with respect to this transaction, the tax benefits relating to the capital loss deductions will not be claimed for financial accounting and reporting purposes until and unless these tax losses are sustained.

In April 2004, Edison International filed California Franchise Tax amended returns for tax years 1997 through 2002 to abate the possible imposition of new California penalty provisions on transactions that may be considered as listed or substantially similar to listed transactions described in an IRS notice that was published in 2001. These transactions include the SCE subsidiary contingent liability company transaction described above. Edison International filed these amended returns under protest retaining its appeal rights.

Midway-Sunset Cogeneration Company

San Joaquin Energy Company, a wholly owned subsidiary of EME, owns a 50% general partnership interest in Midway-Sunset, which owns a 225-MW cogeneration facility near Fellows, California. Midway-Sunset is a party to several proceedings pending at the FERC because Midway-Sunset was a seller in the PX and ISO markets during 2000 and 2001, both for its own account and on behalf of SCE and PG&E, the utilities to which the majority of Midway-Sunset's power was contracted for sale. As a seller into the PX and ISO markets, Midway-Sunset is potentially liable for refunds to purchasers in these markets. See "Regulatory Matters—Current Developments—FERC Refund Proceedings".

The claims asserted against Midway-Sunset for refunds related to power sold into the PX and ISO markets, including power sold on behalf of SCE and PG&E, are estimated to be less than $70 million for all periods under consideration. Midway-Sunset did not retain any proceeds from power sold into the PX and ISO markets on behalf of SCE and PG&E in excess of the amounts to which it was entitled under the pre-existing power sales contracts, but instead passed through those proceeds to the utilities. Since the proceeds were passed through to the utilities, EME believes that PG&E and SCE are obligated to reimburse Midway-Sunset for any refund liability that it incurs as a result of sales made into the PX and ISO markets on their behalves.

During this period, amounts SCE received from Midway-Sunset were credited to SCE's customers against power purchase expenses through the ratemaking mechanism in place at that time. SCE believes that any net amounts reimbursed to Midway-Sunset would be substantially recoverable from its customers through current regulatory mechanisms. SCE does not expect any reimbursement to Midway-Sunset to have a material impact on earnings.

Navajo Nation Litigation

The Navajo Nation filed a complaint in June 1999 in the District Court against SCE, among other defendants, arising out of the coal supply agreement for Mohave. The complaint asserts claims for, among other things, violations of the federal RICO statute, interference with fiduciary duties and contractual relations, fraudulent misrepresentations by nondisclosure, and various contract-related claims. The complaint claims that the defendants' actions prevented the Navajo Nation from obtaining the full value in royalty rates for the coal supplied to Mohave. The complaint seeks damages of not less than $600 million, trebling of that amount, and punitive damages of not less than $1 billion.

In April 2004, the District Court dismissed SCE's motion for summary judgment and concluded that a 2003 U.S. Supreme Court decision in an on-going related lawsuit by the Navajo Nation against the U.S. Government did not preclude the Navajo Nation from pursuing its RICO and intentional tort claims.

Pursuant to a joint request of the parties, the District Court granted a stay of the action on October 5, 2004 to allow the parties to attempt to negotiate a resolution of the issues associated with Mohave with the assistance of a facilitator. An initial organizational session was held with the facilitator on October 14, 2004 and negotiations are on-going. On July 28, 2005, the District Court issued an order removing the case from its active calendar, subject to reinstatement at the request of any party.

SCE cannot predict the outcome of the 1999 Navajo Nation's complaint against SCE, the ultimate impact on the complaint of the Supreme Court's 2003 decision and the on-going litigation by the Navajo Nation against the Government in the related case, or the impact on the facilitated negotiations of the Mohave co-owners' announced decisions to discontinue efforts to return Mohave to service.

Nuclear Insurance

Federal law limits public liability claims from a nuclear incident to $10.8 billion. SCE and other owners of San Onofre and Palo Verde have purchased the maximum private primary insurance available ($300 million). The balance is covered by the industry's retrospective rating plan that uses deferred premium charges to every reactor licensee if a nuclear incident at any licensed reactor in the United States results in claims and/or costs which exceed the primary insurance at that plant site. Federal regulations require this secondary level of financial protection. The NRC exempted San Onofre Unit 1 from this secondary level, effective June 1994. The current maximum deferred premium for each nuclear incident is $101 million per reactor, but not more than $15 million per reactor may be charged in any one year for each incident. The maximum deferred premium per reactor and the yearly assessment per reactor for each nuclear incident will be adjusted for inflation on a 5-year schedule. The next inflation adjustment will occur no later than August 20, 2008. Based on its ownership interests, SCE could be required to pay a maximum of $201 million per nuclear incident. However, it would have to pay no more than $30 million per incident in any one year. Such amounts include a 5% surcharge if additional funds are needed to satisfy public liability claims and are subject to adjustment for inflation. If the public liability limit above is insufficient, federal regulations may impose further revenue-raising measures to pay claims, including a possible additional assessment on all licensed reactor operators.

Property damage insurance covers losses up to $500 million, including decontamination costs, at San Onofre and Palo Verde. Decontamination liability and property damage coverage exceeding the primary $500 million also has been purchased in amounts greater than federal requirements. Additional insurance covers part of replacement power expenses during an accident-related nuclear unit outage. A mutual insurance company owned by utilities with nuclear facilities issues these policies. If losses at any nuclear facility covered by the arrangement were to exceed the accumulated funds for these insurance programs, SCE could be assessed retrospective premium adjustments of up to $42 million per year. Insurance premiums are charged to operating expense.

Palo Verde Nuclear Generating Station Outage and Inspection

Between December 2005 when Palo Verde Unit 1 returned to service from its refueling and steam generator replacement outage and March 2006, Palo Verde Unit 1 operated at between 25% and 32% power level. The need to operate at a reduced power level was due to the vibration level in one of the unit's shutdown cooling lines. On March 21, 2006, Arizona Public Service, the operating agent for Palo Verde Unit 1, removed the unit from service in order to resolve the problem. The vibration problem was resolved and Palo Verde Unit 1 was returned to service on July 7, 2006. Incremental replacement power costs incurred during the outage and periods of reduced power operation of approximately $34 million are expected to be recovered through the ERRA rate-making mechanism.

The NRC held three special inspections of Palo Verde, between March 2005 and February 2007. A follow-up to the first inspection resulted in a finding that Palo Verde had not established adequate measures to ensure that certain corrective actions were effective to address the root cause of the event. The second recent inspection identified five violations, but none of those resulted in increased NRC scrutiny. The most recent inspection, concerning the failure of an emergency backup generator at Palo Verde Unit 3 identified a violation that, combined with the first inspection finding, will cause the NRC to undertake additional oversight inspections of Palo Verde. In addition, Palo Verde will be required to take additional corrective actions, including surveys of its plant personnel and self-assessments of its programs and procedures, which will increase costs to both Palo Verde and its co-owners, including

SCE. Because the surveys and self-assessments have not yet occurred and are critical to determining what other actions Palo Verde will need to take to address the NRC's concerns, SCE cannot at this time predict how much the costs will increase.

Spent Nuclear Fuel

Under federal law, the DOE is responsible for the selection and construction of a facility for the permanent disposal of spent nuclear fuel and high-level radioactive waste. The DOE did not meet its obligation to begin acceptance of spent nuclear fuel not later than January 31, 1998. It is not certain when the DOE will begin accepting spent nuclear fuel from San Onofre or other nuclear power plants. Extended delays by the DOE have led to the construction of costly alternatives and associated siting and environmental issues. SCE has paid the DOE the required one-time fee applicable to nuclear generation at San Onofre through April 6, 1983 (approximately $24 million, plus interest). SCE is also paying the required quarterly fee equal to 0.1¢-per-kWh of nuclear-generated electricity sold after April 6, 1983. On January 29, 2004, SCE, as operating agent, filed a complaint against the DOE in the United States Court of Federal Claims seeking damages for the DOE's failure to meet its obligation to begin accepting spent nuclear fuel from San Onofre. The case was stayed through April 7, 2006, when SCE and the DOE filed a Joint Status Report in which SCE sought to lift the stay and the government opposed lifting the stay. On June 5, 2006, the Court of Federal Claims lifted the stay on SCE's case and established a discovery schedule. A Joint Status Report is due on September 7, 2007, regarding further proceedings in this case and presumably including establishing a trial date.

SCE has primary responsibility for the interim storage of spent nuclear fuel generated at San Onofre. Spent nuclear fuel is stored in the San Onofre Units 2 and 3 spent fuel pools and the San Onofre independent spent fuel storage installation where all of Unit 1's spent fuel located at San Onofre is stored. There is now sufficient space in the Unit 2 and 3 spent fuel pools to meet plant requirements through mid-2007 and mid-2008, respectively. In order to maintain a full core off-load capability, SCE began moving Unit 2 spent fuel into the independent spent fuel storage installation in late February 2007.

There are now sufficient dry casks and modules available to the independent spent fuel storage installation to meet plant requirements through 2008. SCE, as operating agent, plans to continually load casks on a schedule to maintain full core off-load capability for both units in order to meet the plant requirements after 2008 until 2022 (the end of the current NRC operating license).

In order to increase on-site storage capacity and maintain core off-load capability, Palo Verde has constructed an independent spent fuel storage facility. Arizona Public Service, as operating agent, plans to continually load dry casks on a schedule to maintain full core off-load capability for all three units.

MARKET RISK EXPOSURES

SCE's primary market risks include fluctuations in interest rates, commodity prices and volumes, and counterparty credit. Fluctuations in interest rates can affect earnings and cash flows. Fluctuations in commodity prices and volumes and counterparty credit losses may temporarily affect cash flows, but are not expected to affect earnings due to expected recovery through regulatory mechanisms. SCE uses derivative financial instruments, as appropriate, to manage its market risks.

Interest Rate Risk

SCE is exposed to changes in interest rates primarily as a result of its borrowing and investing activities used for liquidity purposes, to fund business operations, and to finance capital expenditures. The nature and amount of SCE's long-term and short-term debt can be expected to vary as a result of future business requirements, market conditions and other factors. In addition, SCE's authorized return on common equity (11.6% for 2006 and 11.4% for 2005), which is established in SCE's annual cost of capital proceeding, is set on the basis of forecasts of interest rates and other factors.

At December 31, 2006, SCE did not believe that its short-term debt and current portion of long-term debt was subject to interest rate risk, due to the fair market value being approximately equal to the carrying value.

At December 31, 2006, the fair market value of SCE's long-term debt was $5.21 billion, compared to a carrying value of $5.17 billion. A 10% increase in market interest rates would have resulted in a $299 million decrease in the fair market value of SCE's long-term debt. A 10% decrease in market interest rates would have resulted in a $331 million increase in the fair market value of SCE's long-term debt.

Commodity Price Risk

SCE is exposed to commodity price risk associated with its purchases for additional capacity and ancillary services to meet its peak energy requirements as well as exposure to natural gas prices associated with power purchased from QFs, fuel tolling arrangements, and its own gas-fired generation, including the Mountainview plant. SCE purchases power from QFs under CPUC-mandated contracts. Contract energy prices for most nonrenewable QFs are based in large part on the monthly southern California border price of natural gas. In addition to the QF contracts, SCE has power contracts in which SCE has agreed to provide the natural gas needed for generation under those power contracts, which are referred to as tolling arrangements.

The CPUC has established resource adequacy requirements which require SCE to acquire and demonstrate enough generating capacity in its portfolio for a planning reserve margin of 15-17% above its peak load as forecast for an average year (see "Regulatory Matters—Current Regulatory Developments—Resource Adequacy Requirements"). The establishment of a sufficient planning reserve margin mitigates, to some extent, exposure to commodity price risk for spot market purchases.

SCE's purchased-power costs and gas expenses, as well as related hedging costs, are recovered through the ERRA. To the extent SCE conducts its power and gas procurement activities in accordance with its CPUC-authorized procurement plan, California statute (Assembly Bill 57) establishes that SCE is entitled to full cost recovery. As a result of these regulatory mechanisms, changes in energy prices may impact SCE's cash flows but are not expected to affect earnings. Certain SCE activities, such as contract administration, SCE's duties as the CDWR's limited agent for allocated CDWR contracts, and portfolio dispatch are reviewed annually by the CPUC for reasonableness. The CPUC has currently established a maximum disallowance cap of $37 million for these activities.

In accordance with CPUC decisions, SCE, as the CDWR's limited agent, performs certain services for CDWR contracts allocated to SCE by the CPUC, including arranging for natural gas supply. Financial and legal responsibility for the allocated contracts remains with the CDWR. The CDWR, through coordination with SCE, has hedged a portion of its expected natural gas requirements for the gas tolling contracts allocated to SCE. Increases in gas prices over time, however, will increase the CDWR's gas costs. California state law permits the CDWR to recover its actual costs through rates established by the CPUC. This would affect rates charged to SCE's customers, but would not affect SCE's earnings or cash flows.

SCE has an active hedging program in place to minimize ratepayer exposure to spot-market price spikes; however, to the extent that SCE does not hedge the exposure to commodity price risk, the unhedged portion is subject to the risks and benefits of spot-market price movements, which are ultimately passed-through to ratepayers.

To mitigate SCE's exposure to spot-market prices, SCE entered into energy options, tolling arrangements, and forward physical contracts. SCE records these derivative instruments on its consolidated balance sheets at fair value unless they meet the definition of a normal purchase or sale. The normal purchases and sales exception requires, among other things, physical delivery in quantities expected to be used or sold over a reasonable period in the normal course of business. SCE enters into contracts for power and gas options, as well as swaps and futures, in order to mitigate its exposure to increases in natural gas and electricity pricing. These transactions are pre-approved by the CPUC or executed in compliance with CPUC-approved procurement plans. The derivative instrument fair values are marked to market at each reporting period. Any fair value changes for recorded derivatives are recorded in purchased-power expense and offset through the provision for regulatory adjustment clauses; therefore, fair value changes do not affect earnings. Hedge accounting is not used for these transactions due to this regulatory accounting treatment. The following table summarizes the fair values of outstanding derivative financial instruments used at SCE to mitigate its exposure to spot market prices:

	December 31, 2006		December 31, 2005	
In millions	**Assets**	**Liabilities**	Assets	Liabilities
Energy options	**$ —**	**$ 10**	$ —	$ 27
Forward physicals (power) and tolling arrangements	**—**	**1**	3	—
Gas options, swaps and forward arrangements	**—**	**101**	105	—
Total	**$ —**	**$ 112**	$ 108	$ 27

Quoted market prices, if available, are used for determining the fair value of contracts, as discussed above. If quoted market prices are not available, internally maintained standardized or industry accepted models are used to determine the fair value. The models are updated with spot prices, forward prices, volatilities and interest rates from regularly published and widely distributed independent sources.

A 10% increase in energy prices at December 31, 2006 would increase the fair value of energy options by approximately $71 million; a decrease in energy prices at December 31, 2006, would decrease the fair value by approximately $39 million. A 10% increase in energy prices at December 31, 2006 would increase the fair value of forward physicals (power) and tolling arrangements by approximately $20 million; a decrease in energy prices at December 31, 2006, would decrease the fair value by approximately $17 million. A 10% increase in gas prices at December 31, 2006 would increase the fair value of gas options, swaps and forward arrangements by approximately $27 million; a decrease in gas prices at December 31, 2006, would decrease the fair value by approximately $154 million.

SCE recorded net unrealized gains (losses) of $(237) million, $90 million and $(9) million for the years ended December 31, 2006, 2005, and 2004, respectively. The 2006 unrealized losses were primarily due to changes in both the gas and power portfolios, as well as decreases in the gas and power forward-market prices.

Credit Risk

Credit risk arises primarily due to the chance that a counterparty under various purchase and sale contracts will not perform as agreed or pay SCE for energy products delivered. SCE uses a variety of strategies to mitigate its exposure to credit risk. SCE's risk management committee regularly reviews procurement credit exposure and approves credit limits for transacting with counterparties. Some counterparties are required to post collateral depending on the creditworthiness of the counterparty and the risk associated with the transaction. SCE follows the credit limits established in its CPUC-approved procurement plan, and accordingly believes that any losses which may occur should be fully recoverable from customers, and therefore are not expected to affect earnings.

RESULTS OF OPERATIONS AND HISTORICAL CASH FLOW ANALYSIS

The following subsections of "Results of Operations and Historical Cash Flow Analysis" provide a discussion on the changes in various line items presented on the Consolidated Statements of Income, as well as a discussion of the changes on the Consolidated Statements of Cash Flows.

Results of Operations

Net Income Available for Common Stock

SCE's net income available for common stock was $776 million in 2006, compared to $725 million in 2005. The increase reflects the impact of higher net revenue authorized in the 2006 GRC decision, higher earnings from SCE's Mountainview plant and a 2006 benefit from a generator settlement, partially offset by higher income tax expense. Net income available for common stock in 2006 also includes an $81 million benefit from resolution of an outstanding regulatory issue related to a portion of revenue collected during the 2001 – 2003 period for state income taxes and a $49 million benefit from favorable resolution of a state apportionment tax issue. Net income available for common stock in 2005 includes a $61 million benefit from an IRS tax settlement and a $55 million benefit related to a favorable FERC decision on a SCE transmission proceeding.

SCE's net income available for common stock was $725 million in 2005, compared to $915 million in 2004. SCE's 2005 net income available for common stock included positive items of $61 million related to a favorable tax settlement (see "Other Developments—Federal and State Income Taxes"), $55 million from a favorable FERC decision on a SCE transmission proceeding and a $14 million incentive benefit from generator refunds related to the California energy crisis period (see "Regulatory Matters—Current Regulatory Developments—FERC Refund Proceedings"). SCE's net income available for common stock in 2004 includes $329 million of positive regulatory and tax items, primarily from implementation of the 2003 GRC decision that was received in July 2004. Excluding these positive items, net income available for common stock was up $9 million due to higher net revenue, including tax benefits, and lower financing costs, partially offset by the impact of a lower CPUC-authorized rate of return in 2005.

Operating Revenue

The following table sets forth the major changes in operating revenue:

In millions	**2006 vs. 2005**	2005 vs. 2004
Operating revenue		
Rate changes (including unbilled)	**$ 1,441**	$ 517
Sales volume changes (including unbilled)	**311**	410
Balancing account overcollections	**(422)**	(324)
Sales for resale	**(463)**	256
SCE's VIEs	**(75)**	177
Other (including intercompany transactions)	**20**	16
Total	**$ 812**	$ 1,052

SCE's retail sales represented approximately 88%, 82%, and 85% of operating revenue for the years ended December 31, 2006, 2005, and 2004, respectively. Due to warmer weather during the summer months, operating revenue during the third quarter of each year is generally significantly higher than other quarters.

Total operating revenue increased $812 million in 2006, compared to 2005 (as shown in the table above). The increase resulting from rate changes was mainly due to rate increases implemented throughout 2006 (see "Regulatory Matters—Current Regulatory Developments—Impact of Regulatory Matters on Customer Rates" for further discussion of these rate changes), primarily relating to the implementation of SCE's 2006 ERRA forecast, implementation of the 2006 GRC decision and modification of the FERC transmission-related rates. The increase in operating revenue resulting from sales volume changes was mainly due to an increase in kWhs sold resulting from record heat conditions experienced in the third quarter of 2006, SCE providing a greater amount of energy to its customers from its own sources in 2006, as compared to 2005, and customer growth. Balancing account overcollections represent the difference between authorized retail revenue and recorded retail revenue that is subject to regulatory balancing account mechanisms. Recorded retail revenue exceeded authorized revenue by approximately $515 million in 2006, compared to approximately $93 million in 2005, due to warmer weather and timing differences from sales and purchases of power subject to balancing account mechanisms. Operating revenue from sales for resale represents the sale of excess energy. Excess energy from SCE sources which may exist at certain times is resold in the energy markets. Sales for resale revenue decreased due to a lesser amount of excess energy in 2006, as compared to 2005, due to higher demand in 2006 resulting from record heat conditions and lower availability of energy from SCE's own sources resulting from the Mohave shutdown and the San Onofre outages. Revenue from sales for resale is refunded to customers through the ERRA balancing account and does not impact earnings. SCE's VIEs revenue represents the recognition of revenue resulting from the consolidation of four gas-fired power plants where SCE is considered the primary beneficiary. These VIEs affect SCE's revenue, but do not affect earnings; the decrease in revenue from SCE's VIEs is primarily due to lower natural gas prices in 2006, compared to 2005. The increase in other revenue was primarily due to higher net investment earnings from SCE's nuclear decommissioning trusts. The nuclear decommissioning trust investment earnings are offset in depreciation, decommissioning and amortization expense and as a result, have no impact on net income.

Total operating revenue increased by $1.1 billion in 2005, compared to 2004 (as shown in the table above). The variance in operating revenue from rate changes reflects the implementation of the 2003 GRC, effective in August 2004. As a result, generation and distribution rates increased revenue by approximately $166 million and $351 million, respectively. The increase in operating revenue resulting from sales volume changes was mainly due to an increase in kWhs sold and SCE providing a greater amount of energy to its customers from its own sources in 2005, compared to 2004. The change in deferred revenue reflects the deferral of approximately $93 million of revenue in 2005, resulting from balancing account overcollections, compared to the recognition of approximately $231 million in 2004. Operating revenue from sales for resale represents the sale of excess energy. As a result of the CDWR contracts allocated to SCE, excess energy from SCE sources may exist at certain times, which then is resold in the energy markets. Revenue from sales for resale is refunded to customers through the ERRA rate-making mechanism and does not impact earnings. SCE's VIEs revenue represents the recognition of revenue resulting from the consolidation of SCE's VIEs effective March 31, 2004.

Amounts SCE bills and collects from its customers for electric power purchased and sold by the CDWR to SCE's customers, CDWR bond-related costs and a portion of direct access exit fees are remitted to the CDWR and none of these collections are recognized as revenue by SCE. These amounts were $2.5 billion, $1.9 billion and $2.5 billion for the years ended December 31, 2006, 2005 and 2004, respectively.

Operating Expenses

Fuel Expense

SCE's fuel expense decreased $81 million in 2006 and increased $383 million in 2005. The 2006 decrease was due to lower fuel expense of approximately $90 million at SCE's Mohave Generating Station resulting from the plant shutdown on December 31, 2005 (see "Regulatory Matters—Mohave Generating Station and Related Proceedings" for further discussion); lower fuel expense of $200 million related to SCE's consolidated VIEs, driven by lower natural gas prices; and lower nuclear fuel expense of $15 million resulting primarily from planned refueling and maintenance outages at SCE's San Onofre Unit 2 and Unit 3; partially offset by higher fuel expense of $240 million resulting from

SCE's Mountainview plant which became operational in December 2005. The 2005 increase was primarily due to the consolidation of SCE's VIEs effective March 31, 2004 resulting in the recognition of fuel expense of $924 million in 2005 and $578 million in 2004.

Purchased-Power Expense

Purchased-power expense increased $787 million in 2006 and increased $290 million in 2005. The 2006 increase was mainly due to net realized and unrealized losses of $575 million, compared to net realized and unrealized gains of $205 million in 2005 (see "Market Risk Exposures—Commodity Price Risk" for further discussion) and lower energy refunds and a generator settlement in 2006. SCE received energy refunds and a generator settlement totaling approximately $180 million in 2006, compared to $285 million in 2005 (see "Regulatory Matters—Current Regulatory Developments—FERC Refund Proceedings" for further discussion). The increase was partially offset by lower power purchased and lower prices from QFs of approximately $95 million (as further discussed below).

The 2005 increase was mainly due to higher firm energy and QF-related purchases, partially offset by net realized and unrealized gains on economic hedging transactions and an increase in energy settlement refunds in 2005, as compared to 2004. Firm energy purchases increased by approximately $670 million resulting from an increase in the number of bilateral contracts in 2005, as compared to 2004, and QF-related purchases increased by approximately $170 million in 2005, as compared to 2004 (as further discussed below). Net realized and unrealized gains related to economic hedging transactions reduced purchased-power expense by approximately $205 million in 2005, as compared to net realized and unrealized losses of approximately $25 million which increased purchased-power expense in 2004. Energy settlement refunds received in 2005 and 2004 were approximately $285 million and $190 million, respectively, further decreasing purchased-power expense in these periods (see "Regulatory Matters—Current Regulatory Developments—FERC Refund Proceedings"). The consolidation of SCE's VIEs effective March 31, 2004 resulted in a $935 million and $669 million reduction in purchased-power expense in 2005 and 2004, respectively.

Federal law and CPUC orders required SCE to enter into contracts to purchase power from QFs at CPUC-mandated prices. Energy payments to gas-fired QFs are generally tied to spot natural gas prices. Energy payments for most renewable QFs are at a fixed price of 5.37¢-per-kWh. In late 2006, certain renewable QF contracts were amended and energy payments for these contracts will be at a fixed price of 6.15¢-per-kWh, effective May 2007. Average spot natural gas prices were lower during 2006 as compared to 2005. The lower expenses related to power purchased from QFs were mainly due to lower average spot natural gas prices and lower kWh purchases.

Provisions for Regulatory Adjustment Clauses – Net

Provisions for regulatory adjustment clauses – net decreased $410 million in 2006 and increased $636 million in 2005. The 2006 decrease was mainly due to net unrealized losses related to economic hedging transactions (mentioned above in purchased-power expense) of approximately $237 million in 2006, that, if realized, would be recovered from ratepayers, compared to unrealized gains of $90 million in 2005, which, if realized, would be refunded to ratepayers (see "Market Risk Exposures—Commodity Price Risk" for further discussion). The decrease also reflects lower energy refunds and generator settlements of $105 million (discussed above) and the resolution of a one-time issue related to a portion of revenue collected during the 2001-2003 period related to state income taxes. SCE was able to determine through the 2006 GRC decision and other regulatory proceedings that the level of revenue collected during that period was appropriate, and as a result recorded a pre-tax gain of $135 million in 2006. The decrease was partially offset by higher net overcollections of purchase-power, fuel, and operation and maintenance expenses of approximately $240 million.

The 2005 increases mainly result from regulatory adjustments recorded in 2004, net overcollections related to balancing accounts, higher net unrealized gains on economic hedging transactions and lower CEMA-related costs. The net regulatory adjustments of $345 million recorded in 2004 related to the implementation of SCE's 2003 GRC decision and the implementation of an ERRA-related CPUC decision (see "Regulatory Matters-Current Regulatory Developments-Energy Resource Recovery Account Proceedings"). In addition to these net regulatory adjustments, the increase reflects higher net overcollections of purchased power, fuel, and operating and maintenance expenses of approximately $65 million which were deferred in balancing accounts for future recovery, higher net unrealized gains of approximately $95 million related to economic hedging transactions (mentioned above in purchased-power expense) that, if realized, would be refunded to ratepayers, and lower costs incurred and deferred of approximately $95 million associated with CEMA-related costs (primarily bark beetle infestation related costs). The 2003 GRC regulatory adjustments primarily related to recognition of revenue from the rate recovery of pension contributions during the time period that the pension plan was fully funded, resolution over the allocation of costs between transmission and distribution for 1998 through 2000, partially offset by the deferral of revenue previously collected during the incremental cost incentive pricing mechanism for dry cask storage, as well as pre-tax gains related to the 1997-1998 generation-related capital additions.

Other Operation and Maintenance Expense

SCE's other operation and maintenance expense increased $155 million in 2006 and $66 million in 2005. The 2006 increase was mainly due to higher generation-related costs of approximately $80 million resulting from the planned refueling and maintenance outages at SCE's San Onofre Unit 2 and Unit 3 and higher maintenance costs at Palo Verde, partially offset by lower costs at Mohave resulting from the plant ceasing operations on December 31, 2005; higher transmission and distribution maintenance cost of approximately $60 million; and increased operation and maintenance expense of $20 million at SCE's Mountainview plant as a result of the plant becoming operational at the end of 2005. Upon implementation of the 2006 GRC in May 2006, costs related to the Mohave shutdown, pensions, PBOPs, and the employee results sharing incentive plan are recovered through balancing account mechanisms. The 2005 increase was mainly due to an increase in reliability costs, demand-side management and energy efficiency costs, and benefit-related costs, partially offset by lower CEMA-related costs and generation-related costs. Reliability costs increased approximately $80 million, as compared to 2004, due to an increase in must-run units to improve the reliability of the California ISO systems operations (which are recovered through regulatory mechanisms approved by the FERC). Demand-side management and energy efficiency costs increased approximately $90 million (which are recovered through regulatory mechanisms approved by the CPUC). Benefit-related costs increased approximately $50 million in 2005, resulting from an increase in heath care costs and value of performance shares. The 2005 increase was partially offset by lower CEMA-related costs (primarily bark beetle infestation related costs) of approximately $95 million and a decrease in generation-related expenses of approximately $90 million, resulting from lower outage and refueling costs (in 2004, there was a scheduled major overhaul at SCE's Four Corners coal facility, as well as a refueling outage at SCE's San Onofre Unit 2). The 2005 variance also reflects an increase of approximately $35 million resulting from the consolidation of SCE's VIEs effective March 31, 2004.

Depreciation, Decommissioning and Amortization Expense

SCE's depreciation, decommissioning and amortization expense increased $111 million in 2006 and $55 million in 2005. The increase in 2006 was mainly due to an increase in depreciation expense resulting from additions to transmission and distribution assets, as well as an increase from the implementation of the depreciation rates authorized in the 2006 GRC decision, and higher net investment earnings from SCE's nuclear decommissioning trusts, which increases revenue and depreciation, with no impact on net income. The increase in 2005 is mainly due to a change in the Palo Verde rate-making mechanisms resulting from the implementation of the 2003 GRC and an increase in depreciation expense resulting from additions to transmission and distribution assets.

Other Income and Deductions

Interest Income

SCE's interest income increased $14 million in 2006 and $24 million in 2005. The 2006 and 2005 increases were mainly due to interest income from balancing accounts that were undercollected during both 2006 and 2005 (see interest expense below), and higher short-term interest rates in 2006, as compared to 2005.

Other Nonoperating Income

SCE's other nonoperating income decreased $42 million in 2006 and increased $43 million in 2005 mainly due to the recognition of approximately $45 million in incentives related to demand-side management and energy efficiency performance and an increase in shareholder incentives related to the FERC settlement refunds recorded in 2005. In addition, SCE recorded shareholder incentives of $6 million, $23 million and $12 million in 2006, 2005 and 2004, respectively (see "Regulatory Matters—Current Regulatory Developments—FERC Refund Proceedings" for further discussion). In addition, other nonoperating income includes rewards approved by the CPUC for the efficient operation of Palo Verde of $10 million in 2005 and $19 million in 2004.

Interest Expense – Net of Amounts Capitalized

SCE's interest expense – net of amounts capitalized increased $40 million in 2006 and decreased $49 million in 2005, mainly due to a 2005 reversal of approximately $25 million of accrued interest expense as a result of a FERC decision allowing recovery of transmission-related costs. The 2006 increase also reflects higher interest expense on balancing account overcollections in 2006, as compared to 2005. The 2005 decrease was also due to lower interest expense on balancing account overcollections, as compared to 2004 and lower interest expense on long-term debt resulting from the redemption of high interest rate debt and issuing new debt with lower interest rates.

Income Tax Expense

The composite federal and state statutory income tax rate was approximately 40% (net of the federal benefit for state income taxes) for all periods presented. The lower effective tax rate of 34.6% realized in 2005 was primarily due to a settlement reached with the California Franchise Tax Board regarding a state apportionment issue (see "Other Developments—Federal and State Income Taxes") partially offset by tax reserve accruals. The lower effective tax rate of 28.1% realized in 2005 was primarily due to settlement of the 1991-1993 IRS audit cycle as well as adjustments made to the tax reserve to reflect the issuance of new IRS regulations and the favorable settlement of other federal and state tax audit issues. The lower effective tax rate of 32.2% realized in 2004 was primarily due to adjustments to tax liabilities relating to prior years.

As a matter of course, Edison International is regularly audited by federal, state and foreign taxing authorities. For further discussion of this matter, see "Other Developments—Federal and State Income Taxes."

Historical Cash Flow Analysis

The "Historical Cash Flow Analysis" section of this MD&A discusses consolidated cash flows from operating, financing and investing activities.

Cash Flows from Operating Activities

Cash provided by operating activities from continuing operations was $2.6 million in 2006, $2.4 million in 2005, and $2.3 million in 2004. The 2006 increase was mainly due to an increase in cash collected from SCE's customers due to increased rates (see "Regulatory Matters—Current Regulatory Developments—Impact of Regulatory Matters on Customer Rates") and increased sales volume due to warmer weather in 2006, as compared to 2005, which contributed to higher balancing account overcollections in 2006, as compared to 2005. The 2006 increase was also attributable to a decrease of $123 million in required margin and collateral deposits in 2006, compared to an increase of $112 million in 2005. The change resulted from a decrease in forward market prices in 2006 from 2005 and settlement of hedge contracts during 2006. In addition, the 2006 change was also due to the timing of cash receipts and disbursements related to working capital items and higher income taxes paid in 2006, compared to 2005. The 2005 change in cash provided by operating activities from continuing operations was mainly due to an increase in income from continuing operations, and the results from the timing of cash receipts and disbursements related to working capital items.

Cash Flows from Financing Activities

Cash used by financing activities from continuing operations mainly consisted of long-term and short-term debt payments.

Financing activities in 2006 included activities related to the rebalancing of SCE's capital structure and rate base growth.

- In January 2006, SCE issued $500 million of first and refunding mortgage bonds which consisted of $350 million of 5.625% bonds due in 2036 and $150 million of floating rate bonds due in 2009. The proceeds from this issuance were used to redeem $150 million of variable rate first and refunding mortgage bonds due in January 2006 and $200 million of its 6.375% first and refunding mortgage bonds due in January 2006.

- In January 2006, SCE issued two million shares of 6% Series C preference stock (noncumulative, $100 liquidation value) and received net proceeds of $197 million.

- In April 2006, SCE issued $331 million of pollution control bonds which consisted of $196 million of 4.10% bonds due in 2028 and $135 million of 4.25% bonds due in 2033. The proceeds from this issuance were used to redeem a total of $331 million of pollution control bonds due in 2008. This transaction was treated as a noncash financing activity.

- In December 2006, SCE issued $400 million of 5.55% first and refunding mortgage bonds due in 2037. The proceeds from this issuance were used for general corporate purposes.

- Financing activities in 2006 also included dividend payments of $300 million paid to Edison International.

Financing activities in 2005 included activities related to the rebalancing of SCE's capital structure.

- In January 2005, SCE issued $650 million of first and refunding mortgage bonds which consisted of $400 million of 5% bonds due in 2016 and $250 million of 5.55% bonds due in 2036. The proceeds from this issuance were used to redeem the remaining $50,000 of its 8% first and refunding mortgage bonds due February 2007 (Series 2003A) and $650 million of the $966 million 8% first and refunding mortgage bonds due February 2007 (Series 2003B).

- In March 2005, SCE issued $203 million of 3.55% pollution control bonds due in 2029. The proceeds from this issuance were used to redeem $49 million of 7.20% pollution control bonds due in 2021 and $155 million of 5.875% pollution control bonds due in 2023. This transaction was treated as a noncash financing activity.

- In April 2005, SCE issued 4,000,000 shares of Series A preference stock (noncumulative, 100% liquidation value) and received net proceeds of approximately $394 million. Approximately $81 million of the proceeds was used to redeem all the outstanding shares of its $100 cumulative preferred stock, 7.23% Series, and approximately $64 million of the proceeds was used to redeem all the outstanding shares of its $100 cumulative preferred stock, 6.05% Series.

- In June 2005, SCE issued $350 million of 5.35% first and refunding mortgage bonds due in 2035 (Series 2005E). A portion of the proceeds from this issuance were used to redeem $316 million of its 8% first and refunding mortgage bonds due in 2007 (Series 2003B).
- In August 2005, SCE issued $249 million of variable rate pollution control bonds due in 2035. The proceeds from this issuance were used to redeem $29 million of 6.90% pollution control bonds due in 2017, $30 million of 6.0% pollution control bonds due in 2027 and $190 million of 6.40% pollution control bonds due in 2024. This transaction was treated as a noncash financing activity.
- Financing activities in 2005 also include dividend payments of $234 million paid to Edison International.

Financing activities in 2004 included activities mainly related to the following activities.

- In January 2004, SCE issued a total of $975 million of bonds, consisting of $300 million of 5% bonds due in 2014, $525 million of 6% bonds due in 2034, and $150 million of floating rate bonds due in 2006. The proceeds from the issuances were used to call at par $300 million of 7.25% first and refunding mortgage bonds due March 2026, $225 million of 7.125% first and refunding mortgage bonds due July 2025, $200 million of 6.9% first and refunding mortgage bonds due October 2018, and $100 million of junior subordinated deferrable interest debentures due June 2044.
- In March 2004, SCE remarketed approximately $550 million of pollution control bonds with varying maturity dates ranging from 2008 to 2040. Approximately $354 million of these pollution control bonds had been held by SCE since 2001 and the remaining $196 million were purchased and reoffered in 2004.
- In March 2004, SCE issued $300 million of 4.65% first and refunding mortgage bonds due in 2015 and $350 million of 5.75% first and refunding mortgage bonds due in 2035. A portion of the proceeds from the March 2004 first and refunding mortgage bond issuances were used to fund the acquisition and construction of the Mountainview plant.
- In December 2004, SCE issued $150 million of floating rate first and refunding mortgage bonds due in 2007. The proceeds from this issuance were used for general corporate purposes.
- During 2004, SCE repaid $125 million of its 5.875% bonds due in September 2004, and the $200 million outstanding balance of its credit facility.
- Financing activities in 2004 also included dividend payments of $756 million paid to Edison International.

Cash Flows from Investing Activities

Cash flows from investing activities are affected by capital expenditures and SCE's funding of nuclear decommissioning trusts.

Investing activities include capital expenditures of $2.2 billion, $1.8 billion and $1.7 billion in 2006, 2005, and 2004, respectively, primarily for transmission and distribution assets. Capital expenditures include $13 million and $166 million in 2006 and 2005, respectively, related to Mountainview and approximately $81 million, $59 million and $70 million in 2006, 2005, and 2004, respectively, for nuclear fuel acquisitions.

ACQUISITIONS

In March 2004, SCE acquired Mountainview, which consisted of a power plant in the early stages of construction in Redlands, California. SCE recommenced full construction of the approximately $600 million project. Mountainview is fully operational.

CRITICAL ACCOUNTING ESTIMATES

The accounting policies described below are viewed by management as critical because their application is the most relevant and material to SCE's results of operations and financial position and these policies require the use of material judgments and estimates. Many of the critical accounting estimates discussed below generally do not impact SCE's earnings since SCE applies SFAS No. 71. However, these critical accounting estimates may impact amounts reported on the consolidated balance sheets.

Rate Regulated Enterprises

SCE applies SFAS No. 71 to the portion of its operations in which regulators set rates at levels intended to recover the estimated costs of providing service, plus a return on capital. Due to timing and other differences in the collection of revenue, these principles allow an incurred cost that would otherwise be charged to expense by a nonregulated entity to be capitalized as a regulatory asset if it is probable that the cost is recoverable through future rates; and conversely these principles allow creation of a regulatory liability for probable future costs collected through rates in advance. SCE's management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as the current regulatory environment, the issuance of rate orders on recovery of the specific incurred cost or a similar incurred cost to SCE or other rate-regulated entities in California, and assurances from the regulator (as well as its primary intervenor groups) that the incurred cost will be treated as an allowable cost (and not challenged) for rate-making purposes. Because current rates include the recovery of existing regulatory assets and settlement of regulatory liabilities, and rates in effect are expected to allow SCE to earn a reasonable rate of return, management believes that existing regulatory assets and liabilities are probable of recovery. This determination reflects the current political and regulatory climate in California and is subject to change in the future. If future recovery of costs ceases to be probable, all or part of the regulatory assets and liabilities would have to be written off against current period earnings. At December 31, 2006, the consolidated balance sheets included regulatory assets of $3.4 billion and regulatory liabilities of $4.1 billion. Management continually evaluates the anticipated recovery of regulatory assets, liabilities, and revenue subject to refund and provides for allowances and/or reserves as appropriate.

Derivative Financial Instruments and Hedging Activities

SCE follows SFAS No. 133, which requires derivative financial instruments to be recorded at their fair value unless an exception applies. SFAS No. 133 also requires that changes in a derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. For derivatives that qualify for hedge accounting, depending on the nature of the hedge, changes in fair value are either offset by changes in the fair value of the hedged assets, liabilities or firm commitments through earnings, or recognized in other comprehensive income until the hedged item is recognized in earnings. The ineffective portion of a derivative's change in fair value is immediately recognized in earnings.

Management's judgment is required to determine if a transaction meets the definition of a derivative and, if it does, whether the normal sales and purchases exception applies or whether individual transactions qualify for hedge accounting treatment.

Derivative assets and liabilities are shown at gross amounts on the consolidated balance sheets, except that net presentation is used when SCE has the legal right of setoff, such as multiple contracts executed with the same counterparty under master netting arrangements.

To mitigate SCE's exposure to spot-market prices, the CPUC has authorized SCE to enter into power purchase contracts (including QFs), energy options, tolling arrangements and forward physical contracts. SCE records these derivative instruments on its consolidated balance sheets at fair value unless they meet the definition of a normal purchase or sale, or are classified as operating leases. The normal purchases exception requires, among other things, physical delivery in quantities expected to be used over a reasonable period in the normal course of business. The derivative instrument fair values are marked to market at each reporting period. Any fair value changes for recorded derivatives are recorded in purchased-power expense and offset through the provision for regulatory adjustment clauses, as the CPUC allows these costs to be recovered from or refunded to customers through a regulatory balancing account mechanism. As a result, fair value changes do not affect earnings. SCE has elected to not use hedge accounting for these transactions due to this regulatory accounting treatment.

Unit-specific contracts (signed or modified after June 30, 2003) in which SCE takes virtually all of the output of a facility are generally considered to be leases under EITF No. 01-8. Leases are not derivatives and are not recorded on the consolidated balance sheets unless they are classified as capital leases.

Most of SCE's QF contracts are not required to be recorded on the consolidated balance sheets because they either don't meet the definition of a derivative or meet the normal purchases and sales exception. However, SCE purchases power from certain QFs in which the contract pricing is based on a natural gas index, but the power is not generated with natural gas. The portion of these contracts that is not eligible for the normal purchases and sales exception is recorded on the consolidated balance sheets at fair value based on financial models.

Determining the fair value of SCE's derivatives under SFAS No. 133 is a critical accounting estimate because the fair value of a derivative is susceptible to significant change resulting from a number of factors, including volatility of energy prices, credits risks, market liquidity and discount rates. See "Market Risk Exposures" and for a description of risk management activities and sensitivities to change in market prices.

Income Taxes

SCE and its eligible subsidiaries are included in Edison International's consolidated federal income tax and combined state franchise tax returns. Under an income tax-allocation agreement approved by the CPUC, SCE's tax liability is computed as if it filed a separate return.

SFAS No. 109, Accounting for Income Taxes, requires the asset and liability approach for financial accounting and reporting for deferred income taxes. SCE uses the asset and liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences.

As part of the process of preparing its consolidated financial statements, SCE is required to estimate its income taxes in each jurisdiction in which it operates. This process involves estimating actual current tax expense together with assessing temporary differences resulting from differing treatment of items, such as depreciation, for tax and accounting purposes. These differences result in deferred tax assets and liabilities, which are included within SCE's consolidated balance sheet. SCE takes certain tax positions it believes are applied in accordance with tax laws. The application of these positions is subject to interpretation and audit by the IRS. As further described in "Other Developments—Federal and State Income Taxes," the IRS has raised issues in the audit of Edison International's tax returns with respect to certain issues at SCE.

Management continually evaluates its income tax exposures and provides for allowances and/or reserves as appropriate reflected in the caption "accrued taxes" on the consolidated balance sheets. See "New Accounting Pronouncements."

Asset Impairment

SCE evaluates long-lived assets whenever indicators of potential impairment exist. SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, requires that if the undiscounted expected future cash flow from a company's assets or group of assets (without interest charges) is less than its carrying value, an asset impairment must be recognized in the financial statements. The amount of impairment is determined by the difference between the carrying amount and fair value of the asset.

The assessment of impairment is a critical accounting estimate because significant management judgment is required to determine: (1) if an indicator of impairment has occurred, (2) how assets should be grouped, (3) the forecast of undiscounted expected future cash flow over the asset's estimated useful life to determine if an impairment exists, and (4) if an impairment exists, the fair value of the asset or asset group. Factors that SCE considers important, which could trigger an impairment, include operating losses from a project, projected future operating losses, the financial condition of counterparties, or significant negative industry or economic trends.

Nuclear Decommissioning

SCE's legal AROs related to the decommissioning of SCE's nuclear power facilities are recorded at fair value. The fair value of decommissioning SCE's nuclear power facilities are based on site-specific studies performed in 2005 for SCE's San Onofre and Palo Verde nuclear facilities. Changes in the estimated costs or timing of decommissioning, or the assumptions underlying these estimates, could cause material revisions to the estimated total cost to decommission these facilities. SCE estimates that it will spend approximately $11.5 billion through 2049 to decommission its active nuclear facilities. This estimate is based on SCE's decommissioning cost methodology used for rate-making purposes, escalated at rates ranging from 1.7% to 7.5% (depending on the cost element) annually.

Nuclear decommissioning costs are recovered in utility rates. These costs are expected to be funded from independent decommissioning trusts that previously received contributions of approximately $32 million per year, effective October 2003. Effective January 2007, the amount allowed to be contributed to the trust increased to approximately $46 million per year. As of December 31, 2006, the decommissioning trust balance was $3.2 billion. Contributions to the decommissioning trusts are reviewed every three years by the CPUC. The contributions are determined from an analysis of estimated decommissioning costs, the current value of trust assets and long-term forecasts of cost escalation and after-tax return on trust investments. Favorable or unfavorable investment performance in a period will not change the amount of contributions for that period. However, trust performance for the three years leading up to a CPUC review proceeding will provide input into future contributions. The CPUC has set certain restrictions related to the investments of these trusts. If additional funds are needed for decommissioning, it is probable that the additional funds will be recoverable through customer rates. Trust funds are recorded on the balance sheet at market value.

Decommissioning of San Onofre Unit 1 is underway. All of SCE's San Onofre Unit 1 decommissioning costs will be paid from its nuclear decommissioning trust funds, subject to CPUC review. The estimated remaining cost to decommission San Onofre Unit 1 of $126 million as of December 31, 2006 is recorded as an ARO liability.

Pensions and Postretirement Benefits Other than Pensions

Pension and other postretirement obligations and the related effects on results of operations are calculated using actuarial models. Two critical assumptions, discount rate and expected return on assets, are important elements of plan expense and liability measurement. Additionally, health care cost trend rates are critical assumptions for postretirement health care plans. These critical assumptions are evaluated at least annually. Other assumptions, such as retirement, mortality and turnover, are evaluated periodically and updated to reflect actual experience.

The discount rate enables SCE to state expected future cash flows at a present value on the measurement date. SCE selects its discount rate by performing a yield curve analysis. This analysis determines the equivalent discount rate on projected cash flows, matching the timing and amount of expected benefit payments. Three yield curves were considered: two corporate yield curves (Citigroup and AON) and a curve based on treasury rates (plus 90 basis points). SCE also compares the yield curve analysis against the Moody's Investor Service AA Corporate bond rate. At the December 31, 2006 measurement date, SCE used a discount rate of 5.75% for both pensions and PBOPs.

To determine the expected long-term rate of return on pension plan assets, current and expected asset allocations are considered, as well as historical and expected returns on plan assets. The expected rate of return on plan assets was 7.5% for pensions and 7.0% for PBOP. A portion of PBOP trusts asset returns are subject to taxation, so the 7.0% figure above is determined on an after-tax basis. Actual time-weighted, annualized returns on the pension plan assets were 15.9%, 10.0% and 10.0% for the one-year, five-year and ten-year periods ended December 31, 2006, respectively. Actual time-weighted, annualized returns on the PBOP plan assets were 13.6%, 7.8%, and 8.2% over these same periods. Accounting principles provide that differences between expected and actual returns are recognized over the average future service of employees.

SCE records pension expense equal to the amount funded to the trusts, as calculated using an actuarial method required for rate-making purposes, in which the impact of market volatility on plan assets is recognized in earnings on a more gradual basis. Any difference between pension expense calculated in accordance with rate-making methods and pension expense calculated in accordance with SFAS No. 71 is accumulated as a regulatory asset or liability, and will, over time, be recovered from or returned to customers. As of December 31, 2006, this cumulative difference amounted to a regulatory liability of $78 million, meaning that the rate-making method has recognized $78 million more in expense than the accounting method since implementation of SFAS No. 87, Employers' Accounting for Pensions, in 1987.

SCE's pension and PBOP plans are subject to the limits established for federal tax deductibility. SCE funds its pension and PBOP plans in accordance with amounts allowed by the CPUC. Executive pension plans and nonutility PBOP plans have no plan assets.

At December 31, 2006, SCE's PBOP plans had a $2.2 billion benefit obligation. Total expense for these plans was $69 million for 2006. The health care cost trend rate is 9.25% for 2007, gradually declining to 5.0% for 2011 and beyond. Increasing the health care cost trend rate by one percentage point would increase the accumulated obligation as of December 31, 2006 by $267 million and annual aggregate service and interest costs by $18 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated obligation as of December 31, 2006 by $238 million and annual aggregate service and interest costs by $16 million.

NEW ACCOUNTING PRONOUNCEMENTS

Accounting Pronouncements Adopted

SFAS No. 123(R) requires companies to use the fair value accounting method for stock-based compensation. SCE implemented SFAS No. 123(R) in the first quarter of 2006 and applied the modified prospective transition method. Under the modified prospective method, the new accounting standard was applied effective January 1, 2006 to the unvested portion of awards previously granted and will be applied to all prospective awards. Prior financial statements were not restated under this method. The new accounting standard resulted in the recognition of expense for all stock-based compensation awards. In addition, SCE elected to calculate the pool of windfall tax benefits as of the adoption of SFAS No. 123(R) based on the method (also known as the short-cut method) proposed in FSP FAS 123(R)-3, Transition Election to Accounting for the Tax Effects of Share-Based Payment Awards. Prior to January 1, 2006, SCE used the intrinsic value method of accounting, which resulted in no recognition of expense for its stock options. Prior to adoption of SFAS No. 123(R), SCE presented all tax benefits of deductions resulting from the exercise of stock options as a component of operating cash flows under the caption "Other liabilities" in the consolidated statements of cash flows.
SFAS No. 123(R)requires the cash flows resulting from the tax benefits that occur from estimated tax deductions in excess of the compensation cost recognized for those options (excess tax benefits) to be

classified as financing cash flows. The $17 million excess tax benefit is classified as a financing cash inflow in 2006. Due to the adoption of SFAS No. 123(R), SCE recorded a cumulative effect adjustment that increased net income by less than $1 million, net of tax, in the first quarter of 2006, mainly to reflect the change in the valuation method for performance shares classified as liability awards and the use of forfeiture estimates.

In April 2006, the FASB issued an FSP FIN 46(R)-6, that specifies how a company should determine the variability to be considered in applying FIN 46(R). FIN 46(R)-6 states that such variability shall be determined based on an analysis of the design of the entity, including the nature of the risks in the entity, the purpose for which the entity was created, and the variability the entity is designed to create and pass along to its interest holders. FIN 46(R)-6 was effective prospectively beginning July 1, 2006, although companies had until December 31, 2006, to elect retrospective application. SCE adopted FIN 46(R)-6 prospectively beginning July 1, 2006. Applying the guidance of FSP FIN 46(R)-6 had no effect on the financial statements for the year ended December 31, 2006.

In September 2006, the FASB issued SFAS No. 158, which amends the accounting by employers for defined benefit pension plans and PBOPs. SFAS No. 158 requires companies to recognize the overfunded or underfunded status of a defined benefit pension and other postretirement plan as an asset and liability in its balance sheet; the asset and/or liability is offset through other comprehensive income (loss). SCE adopted SFAS No. 158 as of December 31, 2006. SCE will record regulatory assets or liabilities instead of charges and credits to other comprehensive income (loss) for its postretirement benefit plans that are recoverable in utility rates, in accordance with SFAS No. 71. SFAS No. 158 also requires companies to align the measurement dates for their plans to their fiscal year-ends; SCE already has a fiscal year-end measurement date for all of its postretirement plans. Upon adoption, SCE recorded additional postretirement benefit assets of $145 million, additional postretirement liabilities of $320 million (including $24 million classified as current), additional regulatory assets of $303 million, regulatory liabilities of $145 million, and a reduction to accumulated other comprehensive income (loss) (a component of shareholder's equity) of $10 million, net of tax.

In September 2006, the Securities & Exchange Commission issued SAB No. 108, which provides interpretive guidance on the consideration of the effects of prior year misstatements in quantifying current year misstatements for the purpose of a materiality assessment. SAB No. 108 requires additional quantitative testing to determine whether a misstatement is material. SCE implemented SAB No. 108 for the filing of its Annual Report on Form 10-K for the year-ended December 31, 2006. Applying the guidance of SAB No. 108 had no effect on the financial statements for the year ended December 31, 2006.

Accounting Pronouncements Not Yet Adopted

In July 2006, the FASB issued an interpretation of FIN 48 clarifying the accounting for uncertainty in income taxes. An enterprise would be required to recognize, in its financial statements, the best estimate of the impact of a tax position by determining if the weight of the available evidence indicates it is more likely than not, based solely on the technical merits, that the position will be sustained on audit. SCE will adopt FIN 48 in first quarter 2007. SCE is currently assessing the impact of FIN 48 on its financial statements. Based on the current status of discussions with tax authorities related to open tax years under audit and other information currently available, implementation of FIN 48 is expected to result in a cumulative-effect adjustment increasing retained earnings in a range of approximately $175 million to $225 million upon adoption. The estimated range is subject to final completion of SCE's analysis and assessment of each uncertain tax position. SCE will continue to monitor and assess new income tax developments.

In September 2006, the FASB issued a new accounting standard on fair value measurements (SFAS No. 157). This statement clarifies the definition of fair value, establishes a framework for measuring fair value and expands the disclosures on fair value measurements. SCE will adopt

SFAS No. 157 on January 1, 2008 and is currently evaluating the impact of adopting this standard on its financial statements.

COMMITMENTS AND INDEMNITIES

SCE's commitments as of December 31, 2006, for the years 2007 through 2011 and thereafter are estimated below:

In millions	2007	2008	2009	2010	2011	Thereafter
Long-term debt maturities and interest(1)	$ 679	$ 325	$ 415	$ 496	$ 245	$ 9,189
Fuel supply contract payments	75	74	51	53	54	259
Purchased-power capacity payments	481	255	144	134	112	642
Operating lease obligations	617	592	531	490	274	1,740
Capital lease obligations	3	3	3	4	—	—
Other commitments	5	5	5	6	6	31
Employee benefit plans contributions(2)	91	—	—	—	—	—
Total	$ 1,951	$ 1,254	$ 1,149	$ 1,183	$ 691	$ 11,861

(1) Amount includes scheduled principal payments for debt outstanding as of December 31, 2006, assuming long-term debt is held to maturity, and related forecast interest payments over the applicable period of the debt.

(2) Amount includes estimated contributions to the pension and PBOP plans. The estimated contributions are not available beyond 2007.

Fuel Supply Contracts

SCE has fuel supply contracts which require payment only if the fuel is made available for purchase. SCE has a coal fuel contract that requires payment of certain fixed charges whether or not coal is delivered.

Power-Purchase Contracts

SCE has power-purchase contracts with certain QFs (cogenerators and small power producers) and other power producers. These contracts provide for capacity payments if a facility meets certain performance obligations and energy payments based on actual power supplied to SCE (the energy payments are not included in the table below). There are no requirements to make debt-service payments. In an effort to replace higher-cost contract payments with lower-cost replacement power, SCE has entered into purchased-power settlements to end its contract obligations with certain QFs. The settlements are reported as power purchase contracts on the consolidated balance sheets.

Operating and Capital Leases

In accordance with EITF No. 01-8, power contracts signed or modified after June 30, 2003, need to be assessed for lease accounting requirements. Unit specific contracts in which SCE takes virtually all of the output of a facility are generally considered to be leases. As of December 31, 2005, SCE had six power contracts classified as operating leases. In April 2006 SCE modified one power contract, and in November 2006 an additional 61 contracts were modified. The modifications to the contracts resulted in a change to the contractual terms of the contracts at which time SCE reassessed these power contracts under EITF No. 01-8 and determined that the contracts are leases and subsequently met the requirements for operating leases under SFAS No. 13, Accounting for Leases. These power contracts had previously been grandfathered relative to EITF No. 01-8 and did not meet the normal purchases and sales exception. As a result, these contracts were recorded on the consolidated balance sheets at fair value in accordance with SFAS No. 133. The fair value changes for these power purchase contracts were previously recorded in purchased-power expense and offset through the provision for regulatory adjustment clauses—net; therefore, fair value changes did not affect earnings. At the time of modification, SCE had assets and liabilities related to mark-to-market gains or losses. Under SFAS No. 133, the assets and liabilities were reclassified to a lease prepayment or accrual and were included in the cost basis of the lease. The lease prepayment and accruals are being amortized over the life of the leases on a straight-line basis. At December 31, 2006, the net liability was $60 million. At December 31, 2006, SCE had 68 power contracts classified as operating leases. In addition, SCE executed a power purchase contract in late 2005 which met accounting requirements for capital leases. This capital lease has a net commitment of $13 million at December 31, 2006, and the capital lease amortization expense and interest expense was $3 million in 2006. The modification resulted in an increase in operating lease commitments and decreased power purchase commitments.

SCE has other operating leases for office space, vehicles, property and other equipment (with varying terms, provisions and expiration dates).

Other Commitments

SCE has an unconditional purchase obligation for firm transmission service from another utility. Minimum payments are based, in part, on the debt-service requirements of the transmission service provider, whether or not the transmission line is operable. The contract requires minimum payments of $57 million through 2016 (approximately $6 million per year).

Indemnities

In connection with the acquisition of Mountainview, SCE agreed to indemnify the seller with respect to specific environmental claims related to SCE's previously owned San Bernardino Generating Station, divested by SCE in 1998 and reacquired as part of the Mountainview acquisition. SCE retained certain responsibilities with respect to environmental claims as part of the original divestiture of the station. The aggregate liability for either party to the purchase agreement for damages and other amounts is a maximum of $60 million. This indemnification for environmental liabilities expires on or before March 12, 2033. SCE has not recorded a liability related to this indemnity.

SCE provides other indemnifications through contracts entered into in the normal course of business. These are primarily indemnifications against adverse litigation outcomes in connection with underwriting agreements, and specified environmental indemnities and income taxes with respect to assets sold. SCE's obligations under these agreements may be limited in terms of time and/or amount, and in some instances SCE may have recourse against third parties for certain indemnities. The obligated amounts of these indemnifications often are not explicitly stated, and the overall maximum amount of the obligation under these indemnifications cannot be reasonably estimated. SCE has not recorded a liability related to these indemnities.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and
Shareholder of Southern California Edison Company

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, cash flows and common shareholder's equity present fairly, in all material respects, the financial position of Southern California Edison Company and its subsidiaries at December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Notes 14, 8 and 1 to the consolidated financial statements, the Company changed the manner in which it accounts for variable interest entities as of March 31, 2004, asset retirement costs as of December 31, 2005, and share-based compensation as of January 1, 2006 and defined benefit pension and other postretirement plans as of December 31, 2006.

//original signed by//

Los Angeles, California
February 28, 2007

Consolidated Statements of Income

Southern California Edison Company

In millions Year ended December 31,	2006	2005	2004
Operating revenue	**$ 10,312**	$ 9,500	$ 8,448
Fuel	**1,112**	1,193	810
Purchased power	**3,409**	2,622	2,332
Provisions for regulatory adjustment clauses – net	**25**	435	(201)
Other operation and maintenance	**2,678**	2,523	2,457
Depreciation, decommissioning and amortization	**1,026**	915	860
Property and other taxes	**206**	193	177
Net gain on sale of utility property and plant	**(1)**	(10)	—
Total operating expenses	**8,455**	7,871	6,435
Operating income	**1,857**	1,629	2,013
Interest income	**58**	44	20
Other nonoperating income	**85**	127	84
Interest expense – net of amounts capitalized	**(400)**	(360)	(409)
Other nonoperating deductions	**(60)**	(65)	(69)
Income before tax and minority interest	**1,540**	1,375	1,639
Income tax expense	**438**	292	438
Minority interest	**275**	334	280
Net income	**827**	749	921
Dividends on preferred and preference stock not subject to mandatory redemption	**51**	24	6
Net income available for common stock	**$ 776**	$ 725	$ 915

Consolidated Statements of Comprehensive Income

In millions Year ended December 31,	2006	2005	2004
Net income	**$ 827**	$ 749	$ 921
Other comprehensive income (loss), net of tax:			
Minimum pension liability adjustment	**7**	(1)	(1)
Termination and amortization of cash flow hedges	**5**	2	3
Comprehensive income	**$ 839**	$ 750	$ 923

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Balance Sheets

In millions December 31,	2006	2005
ASSETS		
Cash and equivalents	**$ 83**	$ 143
Restricted cash	**56**	57
Margin and collateral deposits	**55**	178
Receivables, less allowances of $29 and $33 for uncollectible accounts at respective dates	**939**	849
Accrued unbilled revenue	**303**	291
Inventory	**232**	220
Accumulated deferred income taxes – net	**250**	—
Derivative assets	**56**	237
Regulatory assets	**554**	536
Other current assets	**54**	92
Total current assets	**2,582**	2,603
Nonutility property – less accumulated provision for depreciation of $633 and $569 at respective dates	**1,046**	1,086
Nuclear decommissioning trusts	**3,184**	2,907
Other investments	**62**	80
Total investments and other assets	**4,292**	4,073
Utility plant, at original cost:		
Transmission and distribution	**17,606**	16,760
Generation	**1,465**	1,370
Accumulated provision for depreciation	**(4,821)**	(4,763)
Construction work in progress	**1,486**	956
Nuclear fuel, at amortized cost	**177**	146
Total utility plant	**15,913**	14,469
Regulatory assets	**2,818**	3,013
Derivative assets	**17**	42
Other long-term assets	**488**	503
Total long-term assets	**3,323**	3,558
Total assets	**$ 26,110**	$ 24,703

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Balances Sheets	Southern California Edison Company	
In millions, except share amounts December 31,	**2006**	2005
LIABILITIES AND SHAREHOLDERS' EQUITY		
Long-term debt due within one year	**$ 396**	$ 596
Accounts payable	**856**	898
Accrued taxes	**193**	242
Accrued interest	**114**	106
Counterparty collateral	**36**	183
Customer deposits	**198**	183
Book overdrafts	**140**	257
Accumulated deferred income taxes – net	**—**	5
Derivative liabilities	**99**	87
Regulatory liabilities	**1,000**	681
Other current liabilities	**624**	723
Total current liabilities	**3,656**	3,961
Long-term debt	**5,171**	4,669
Accumulated deferred income taxes – net	**2,675**	2,815
Accumulated deferred investment tax credits	**112**	119
Customer advances	**160**	153
Derivative liabilities	**77**	101
Power-purchase contracts	**32**	64
Accumulated provision for pensions and benefits	**809**	500
Asset retirement obligations	**2,749**	2,621
Regulatory liabilities	**3,140**	2,962
Other deferred credits and other long-term liabilities	**802**	681
Total deferred credits and other liabilities	**10,556**	10,016
Total liabilities	**19,383**	18,646
Commitments and contingencies (Note 6)		
Minority interest	**351**	398
Common stock, no par value (434,888,104 shares outstanding at each date)	**2,168**	2,168
Additional paid-in capital	**383**	361
Accumulated other comprehensive loss	**(14)**	(16)
Retained earnings	**2,910**	2,417
Total common shareholder's equity	**5,447**	4,930
Preferred and preference stock not subject to mandatory redemption	**929**	729
Total shareholders' equity	**6,376**	5,659
Total liabilities and shareholders' equity	**$ 26,110**	$ 24,703

Authorized common stock is 560 million shares at each reporting period.

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Statements of Cash Flows

In millions Year ended December 31,	2006	2005	2004
Cash flows from operating activities:			
Net income	**$ 827**	$ 749	$ 921
Adjustments to reconcile to net cash provided by operating activities:			
Depreciation, decommissioning and amortization	**1,026**	915	860
Loss on impairment of nuclear decommissioning trusts	**54**	—	—
Other amortization	**79**	96	90
Minority interest	**275**	334	280
Deferred income taxes and investment tax credits	**(358)**	34	514
Regulatory assets – long-term	**92**	387	442
Regulatory liabilities – long-term	**18**	(168)	(69)
Derivative assets – long-term	**25**	(42)	—
Derivative liabilities – long-term	**(24)**	97	4
Other assets	**(119)**	88	(44)
Other liabilities	**341**	(25)	14
Margin and collateral deposits – net of collateral received	**(24)**	70	(33)
Receivables and accrued unbilled revenue	**51**	(202)	(9)
Derivative assets – short-term	**181**	(211)	(23)
Derivative liabilities – short-term	**12**	74	13
Inventory and other current assets	**22**	(66)	13
Regulatory assets – short-term	**(18)**	17	(254)
Regulatory liabilities – short-term	**318**	192	(169)
Accrued interest and taxes	**(41)**	(126)	(111)
Accounts payable and other current liabilities	**(131)**	177	(165)
Net cash provided by operating activities	**2,606**	2,390	2,274
Cash flows from financing activities:			
Long-term debt issued	**900**	1000	1,775
Long-term debt issuance costs	**(24)**	(20)	(28)
Long-term debt repaid	**(352)**	(1,040)	(966)
Bonds remarketed – net	**—**	—	350
Issuance of preference stock	**196**	591	—
Redemption of preferred stock	**—**	(148)	(2)
Rate reduction notes repaid	**(246)**	(246)	(246)
Short-term debt financing – net	**—**	(88)	(112)
Change in book overdrafts	**(118)**	25	43
Shares purchased for stock-based compensation	**(103)**	(115)	(60)
Proceeds from stock option exercises	**45**	53	29
Excess tax benefits related to stock option exercises	**17**	—	—
Minority interest	**(322)**	(345)	(290)
Dividends paid	**(300)**	(234)	(756)
Net cash used by financing activities	**(307)**	(567)	(263)
Cash flows from investing activities:			
Capital expenditures	**(2,226)**	(1,808)	(1,678)
Acquisition costs related to nonutility generation plant	**—**	—	(285)
Proceeds from nuclear decommissioning trust sales	**3,010**	2,067	2,416
Purchases of nuclear decommissioning trust investments	**(3,150)**	(2,159)	(2,525)
Customer advances for construction and other investments	**7**	98	9
Net cash used by investing activities	**(2,359)**	(1,802)	(2,063)
Effect of consolidation of variable interest entities	**—**	—	79
Net increase (decrease) in cash and equivalents	**(60)**	21	27
Cash and equivalents, beginning of year	**143**	122	95
Cash and equivalents, end of year	**$ 83**	$ 143	$ 122

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Statements of Changes in Common Shareholders' Equity

Southern California Edison Company

In millions	Common Stock	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Common Shareholder's Equity
Balance at December 31, 2003	$ 2,168	$ 338	$ (19)	$ 1,868	$ 4,355
Net income				921	921
Minimum pension liability adjustment			(1)		(1)
Amortization of cash flow hedges			5		5
Tax effect			(2)		(2)
Dividends declared on common stock				(750)	(750)
Dividends declared on preferred stock not subject to mandatory redemption				(6)	(6)
Shares purchased for stock-based compensation		(17)		(43)	(60)
Proceeds from stock option exercises				29	29
Noncash stock-based compensation		30			30
Capital stock expense and other		(1)		1	—
Balance at December 31, 2004	$ 2,168	$ 350	$ (17)	$ 2,020	$ 4,521
Net income				749	749
Minimum pension liability adjustment			(2)		(2)
Tax effect			1		1
Amortization of cash flow hedges			4		4
Tax effect			(2)		(2)
Dividends declared on common stock				(285)	(285)
Dividends declared on preferred and preference stock not subject to mandatory redemption				(24)	(24)
Shares purchased for stock-based compensation		(19)		(95)	(114)
Proceeds from stock option exercises				53	53
Noncash stock-based compensation		11			11
Excess tax benefits related to stock option exercises		29			29
Capital stock expense and other		(10)		(1)	(11)
Balance at December 31, 2005	$ 2,168	$ 361	$ (16)	$ 2,417	$ 4,930
Net income				827	827
Minimum pension liability adjustment			12		12
Tax effect			(5)		(5)
SFAS No. 158 – Postretirement benefits			(17)		(17)
Tax effect			7		7
Termination and amortization of cash flow hedges			8		8
Tax effect			(3)		(3)
Dividends declared on common stock				(240)	(240)
Dividends declared on preferred and preference stock not subject to mandatory redemption				(51)	(51)
Shares purchased for stock-based compensation		(15)		(88)	(103)
Proceeds from stock option exercises				45	45
Noncash stock-based compensation		23			23
Excess tax benefits related to stock option exercises		17			17
Capital stock expense and other		(3)			(3)
Balance at December 31, 2006	$ 2,168	$ 383	$ (14)	$ 2,910	$ 5,447

Authorized common stock is 560 million shares. The outstanding common stock is 434,888,104 shares for all years reported.

The accompanying notes are an integral part of these consolidated financial statements.

Notes to Consolidated Financial Statements

Significant accounting policies are discussed in Note 1, unless discussed in the respective Notes for specific topics.

Note 1. Summary of Significant Accounting Policies

SCE is a rate-regulated electric utility that supplies electric energy to a 50,000 square-mile area of central, coastal and southern California.

Basis of Presentation

The consolidated financial statements include SCE, its subsidiaries and VIEs for which SCE is the primary beneficiary. Effective March 31, 2004, SCE began consolidating four cogeneration projects from which SCE typically purchases 100% of the energy produced under long-term power-purchase agreements, in accordance with FIN 46(R). Intercompany transactions have been eliminated.

SCE's accounting policies conform to accounting principles generally accepted in the United States of America, including SFAS No. 71, which reflect the rate-making policies of the CPUC and the FERC.

Certain prior-year amounts were reclassified to conform to the December 31, 2006 financial statement presentation.

Financial statements prepared in conformity with accounting principles generally accepted in the United States of America require management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingency assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reported period. Actual results could differ from those estimates.

SCE's outstanding common stock is owned entirely by its parent company, Edison International.

Book Overdrafts

Book overdrafts represent outstanding checks in excess of cash funds that are on deposit with financial institutions. Monthly, SCE reclassifies the amount for checks issued but not yet paid by the financial institution, from cash to book overdrafts.

Cash and Equivalents

Cash and equivalents consist of cash and cash equivalents. Cash equivalents consist of other investments of $1 million at December 31, 2006 and $16 million at December 31, 2005 with original maturities of three months or less. Additionally, cash and equivalents of $78 million at December 31, 2006 and $120 million at December 31, 2005 are included for the VIE segment. For a discussion of restricted cash, see "Restricted Cash."

Deferred Financing Costs

Debt premium, discount and issuance expenses are deferred and amortized on a straight-line basis through interest expense over the life of each related issue. Under CPUC rate-making procedures, debt reacquisition expenses are amortized over the remaining life of the reacquired debt or, if refinanced, the life of the new debt. California law prohibits SCE from incurring or guaranteeing debt for its nonutility affiliates. SCE had unamortized loss on reacquired debt of $318 million at December 31, 2006 and $323 million at December 31, 2005 reflected in "regulatory assets" in the long-term section of the consolidated balance sheets. SCE had unamortized debt issuance costs of $46 million at December 31, 2006 and $40 at December 31, 2005 reflected in "other long-term assets" on the consolidated balance sheets.

Derivative Instruments and Hedging Activities

SCE uses derivative financial instruments to manage financial exposure on its investments and fluctuations in commodity prices and interest rates.

SCE is exposed to credit loss in the event of nonperformance by counterparties. To mitigate credit risk from counterparties, master netting agreements are used whenever possible and counterparties may be required to pledge collateral depending on the creditworthiness of each counterparty and the risk associated with the transaction. SCE does not expect the counterparties to fail to meet their obligations.

SCE records its derivative instruments on its consolidated balance sheets at fair value unless they meet the definition of a normal purchase or sale. The normal purchases and sales exception requires, among other things, physical delivery in quantities expected to be used or sold over a reasonable period in the normal course of business.

Derivative assets and liabilities are shown at gross amounts on the consolidated balance sheets, except that net presentation is used when SCE has the legal right of setoff, such as multiple contracts executed with the same counterparty under master netting arrangements. The results of derivative activities are recorded as part of cash flows from operating activities in the consolidated statements of cash flows.

To mitigate SCE's exposure to spot-market prices, the CPUC has authorized SCE to enter into power purchase contracts (including QFs), energy options, tolling arrangements and forward physical contracts. SCE records these derivative instruments on its consolidated balance sheets at fair value unless they meet the definition of a normal purchase or sale (as discussed above), or are classified as operating leases. The normal purchases exception requires, among other things, physical delivery in quantities expected to be used over a reasonable period in the normal course of business. The derivative instrument fair values are marked to market at each reporting period. Any fair value changes for recorded derivatives are recorded in purchased-power expense and offset through the provision for regulatory adjustment clauses, as the CPUC allows these costs to be recovered from or refunded to customers through a regulatory balancing account mechanism. As a result, fair value changes do not affect earnings. SCE has elected to not use hedge accounting for these transactions due to this regulatory accounting treatment.

Unit-specific contracts (signed or modified after June 30, 2003) in which SCE takes virtually all of the output of a facility are generally considered to be leases under EITF No. 01-8. Leases are not derivatives and are not recorded on the consolidated balance sheets unless they are classified as capital leases.

Most of SCE's QF contracts are not required to be recorded on the consolidated balance sheets because they either don't meet the definition of a derivative or meet the normal purchases and sales exception. However, SCE purchases power from certain QFs in which the contract pricing is based on a natural gas index, but the power is not generated with natural gas. The portion of these contracts that is not eligible for the normal purchases and sales exception is recorded on the consolidated balance sheets at fair value.

See further information about SCE's derivative instruments in Note 2.

Dividend Restriction

The CPUC regulates SCE's capital structure and limits the dividends it may pay Edison International. SCE's authorized capital structure includes a common equity component of 48%. SCE determines compliance with this capital structure based on a 13-month weighted-average calculation. At December 31, 2006, SCE's 13-month weighted-average common equity component of total capitalization was 49.46%. At December 31, 2006, SCE had the capacity to pay $164 million in additional dividends based on the 13-month weighted-average method. However, based on recorded December 31, 2006 balances, SCE's common equity to total capitalization ratio (as adjusted for rate-making purposes) was 48.65%. SCE had the capacity to pay $73 million of additional dividends to Edison International based on December 31, 2006 recorded balances.

Impairment of Long-Lived Assets

SCE evaluates the impairment of its long-lived assets based on a review of estimated cash flows expected to be generated whenever events or changes in circumstances indicate the carrying amount of such assets may not be recoverable. If the carrying amount of the asset exceeds the amount of the expected future cash flows, undiscounted and without interest charges, then an impairment loss must be recognized in accordance with SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets. In accordance with SFAS No. 71, impaired assets are recorded as a regulatory asset if it is deemed probable that such amounts will be recovered from the ratepayers.

Income Taxes

SCE and its subsidiaries are included in Edison International's consolidated federal income tax and combined state franchise tax returns. Under an income tax allocation agreement approved by the CPUC, SCE's tax liability is computed as if it filed a separate return.

As part of the process of preparing its consolidated financial statements, SCE is required to estimate its income taxes in each of the jurisdictions in which it operates. This process involves estimating actual current tax exposure together with assessing temporary differences resulting from differing treatment of items, such as depreciable property for tax and accounting purposes. These differences result in deferred tax assets and liabilities, which are included within SCE's consolidated balance sheets.

Income tax expense includes the current tax liability from operations and the change in deferred income taxes during the year. Investment tax credits are deferred and amortized over the lives of the related properties.

For a further discussion of income taxes, see Note 4.

Inventory

Inventory is stated at the lower of cost or market, cost being determined by the first-in, first-out method for fuel and the average cost method for materials and supplies.

Leases

Rent expense under operating leases for vehicle, office space and other equipment is levelized over the terms of the leases.

Capital leases are reported as long-term obligations on the consolidated balance sheets under the caption, "Other deferred credits and other long-term liabilities." In accordance with SFAS No. 71, SCE's capital lease amortization expense and interest expense are reflected in the caption "Purchased power" on the consolidated statements of income.

Margin and Collateral Deposits

Margin and collateral deposits include margin requirements and cash deposited with counterparties and brokers as credit support under margining agreements for power and gas price risk management activities. The amount of margin and collateral deposits varies based on changes in the value of the agreements. Deposits with counterparties and brokers earn interest at various rates.

New Accounting Pronouncements

Accounting Pronouncements Adopted

SFAS No. 123(R) requires companies to use the fair value accounting method for stock-based compensation. SCE implemented SFAS No. 123(R) in the first quarter of 2006 and applied the modified prospective transition method. Under the modified prospective method, the new accounting standard was applied effective January 1, 2006 to the unvested portion of awards previously granted and will be applied to all prospective awards. Prior financial statements were not restated under this method. The new accounting standard resulted in the recognition of expense for all stock-based compensation awards. In addition, SCE elected to calculate the pool of windfall tax benefits as of the adoption of SFAS No. 123(R) based on the method (also known as the short-cut method) proposed in FSP FAS 123(R)-3, Transition Election to Accounting for the Tax Effects of Share-Based Payment Awards. Prior to January 1, 2006, SCE used the intrinsic value method of accounting, which resulted in no recognition of expense for its stock options. Prior to adoption of SFAS No. 123(R), SCE presented all tax benefits of deductions resulting from the exercise of stock options as a component of operating cash flows under the caption "Other liabilities" in the consolidated statements of cash flows. SFAS No. 123(R) requires the cash flows resulting from the tax benefits that occur from estimated tax deductions in excess of the compensation cost recognized for those options (excess tax benefits) to be classified as financing cash flows. The $17 million excess tax benefit is classified as a financing cash inflow in 2006. Due to the adoption of SFAS No. 123(R), SCE recorded a cumulative effect adjustment that increased net income by less than $1 million, net of tax, in the first quarter of 2006, mainly to reflect the change in the valuation method for performance shares classified as liability awards and the use of forfeiture estimates.

In April 2006, the FASB issued FSP FIN 46(R)-6, that specifies how a company should determine the variability to be considered in applying FIN 46(R). FIN 46(R)-6 states that such variability shall be determined based on an analysis of the design of the entity, including the nature of the risks in the entity, the purpose for which the entity was created, and the variability the entity is designed to create and pass along to its interest holders. FIN 46(R)-6 was effective prospectively beginning July 1, 2006, although companies had until December 31, 2006, to elect retrospective application. SCE adopted FIN 46(R)-6 prospectively beginning July 1, 2006. Applying the guidance of FSP FIN 46(R)-6 had no effect on the financial statements for the year ended December 31, 2006.

In September 2006, the FASB issued SFAS No. 158, which amends the accounting by employers for defined benefit pension plans and PBOPs. SFAS No. 158 requires companies to recognize the overfunded or underfunded status of a defined benefit pension and other postretirement plan as an asset and liability in its balance sheet; the asset and/or liability is offset through other comprehensive income (loss). SCE adopted SFAS No. 158 as of December 31, 2006. SCE will record regulatory assets or liabilities instead of charges and credits to other comprehensive income (loss) for its postretirement benefit plans that are recoverable in utility rates, in accordance with SFAS No. 71. SFAS No. 158 also requires companies to align the measurement dates for their plans to their fiscal year-ends; SCE already has a fiscal year-end measurement date for all of its postretirement plans. Upon adoption, SCE recorded additional postretirement benefit assets of $145 million, additional postretirement liabilities of $320 million (including $24 million classified as current), additional regulatory assets of $303 million, regulatory liabilities of $145 million, and a reduction to accumulated other comprehensive income (loss) (a component of shareholder's equity) of $10 million, net of tax.

In September 2006, the Securities & Exchange Commission issued SAB No. 108, which provides interpretive guidance on the consideration of the effects of prior year misstatements in quantifying current year misstatements for the purpose of a materiality assessment. SAB No. 108 requires additional quantitative testing to determine whether a misstatement is material. SCE implemented SAB No. 108 for the filing of its Annual Report on Form 10-K for the year-ended December 31, 2006. Applying the guidance of SAB No. 108 had no effect on the financial statements for the year ended December 31, 2006.

Accounting Pronouncements Not Yet Adopted

In July 2006, the FASB issued an interpretation of FIN 48 clarifying the accounting for uncertainty in income taxes. An enterprise would be required to recognize, in its financial statements, the best estimate of the impact of a tax position by determining if the weight of the available evidence indicates it is more likely than not, based solely on the technical merits, that the position will be sustained on audit. SCE will adopt FIN 48 in first quarter 2007. SCE is currently assessing the impact of FIN 48 on its financial statements. Based on the current status of discussions with tax authorities related to open tax years under audit and other information currently available, implementation of FIN 48 is expected to result in a cumulative-effect adjustment increasing retained earnings in a range of approximately $175 million to $225 million upon adoption. The estimated range is subject to final completion of SCE's analysis and assessment of each uncertain tax position. SCE will continue to monitor and assess new income tax developments.

In September 2006, the FASB issued a new accounting standard on fair value measurements (SFAS No. 157). This statement clarifies the definition of fair value, establishes a framework for measuring fair value and expands the disclosures on fair value measurements. SCE will adopt SFAS No. 157 on January 1, 2008 and is currently evaluating the impact of adopting this standard on its financial statements.

Nuclear Decommissioning

As a result of SCE's adoption of SFAS No. 143 in 2003, SCE recorded the fair value of its liability for AROs, primarily related to the decommissioning of its nuclear power facilities. At that time, SCE adjusted its nuclear decommissioning obligation, capitalized the initial costs of the ARO into a nuclear-related ARO regulatory asset, and also recorded an ARO regulatory liability as a result of timing differences between the recognition of costs recorded in accordance with SFAS No. 143 and the recovery of the related asset retirement costs through the rate-making process.

SCE plans to decommission its nuclear generating facilities by a prompt removal method authorized by the NRC. Decommissioning is expected to begin after the plants' operating licenses expire. The operating licenses currently expire in 2022 for San Onofre Units 2 and 3, and in 2025, 2026 and 2027 for the Palo Verde units. Decommissioning costs, which are recovered through nonbypassable customer rates over the term of each nuclear facility's operating license, are recorded as a component of depreciation expense, with a corresponding credit to the ARO regulatory liability. The earnings impact of amortization of the ARO asset included within the unamortized nuclear investment and accretion of the ARO liability, both established under SFAS No. 143, are deferred as increases to the ARO regulatory liability account, with no impact on earnings.

SCE has collected in rates amounts for the future costs of removal of its nuclear assets, and has placed those amounts in independent trusts. The cost of removal amounts, in excess of fair value collected for assets not legally required to be removed, are classified as regulatory liabilities.

All investments are classified as available-for-sale. SCE has debt and equity investments for the nuclear decommissioning trust funds. Unrealized gains and losses on decommissioning trust funds increase or decrease the related regulatory asset or liability. SCE reviews each security for other-than-temporary impairment losses on the first and last day of each month. If the fair value on both days is less than the weighted-average cost for that security, SCE will recognize a realized loss for the other-than-temporary impairment. If the fair value is greater or less than the cost for that security at the time of sale, SCE will recognize a related realized gain or loss, respectively. Under SFAS No. 71, SCE receives recovery of these realized gains and losses through rates; therefore this accounting treatment does not affect SCE's earnings.

For a further discussion about nuclear decommissioning trusts see "Nuclear Decommissioning Commitment" in Note 6.

Planned Major Maintenance

Certain plant facilities require major maintenance on a periodic basis. These costs are expensed as incurred.

Property and Plant

Utility Plant

Utility plant additions, including replacements and betterments, are capitalized. Such costs include direct material and labor, construction overhead, a portion of administrative and general costs capitalized at a rate authorized by the CPUC, and AFUDC. AFUDC represents the estimated cost of debt and equity funds that finance utility-plant construction. Currently, AFUDC debt and equity is capitalized during plant construction and reported in interest expense and other nonoperating income, respectively. AFUDC is recovered in rates through depreciation expense over the useful life of the related asset. Depreciation of utility plant is computed on a straight-line, remaining-life basis.

Depreciation expense stated as a percent of average original cost of depreciable utility plant was, on a composite basis, 4.2% for 2006, 3.9% for 2005 and 3.9% for 2004.

AFUDC – equity was $32 million in 2006, $25 million in 2005 and $23 million in 2004. AFUDC – debt was $18 million in 2006, $14 million in 2005 and $12 million in 2004.

Replaced or retired property costs are charged to the accumulated provision for depreciation. Cash payments for removal costs less salvage reduce the liability for AROs.

In May 2003, the Palo Verde units returned to traditional cost-of-service ratemaking while San Onofre Units 2 and 3 returned to traditional cost-of-service ratemaking in January 2004. SCE's nuclear plant investments made prior to the return to cost-of-service ratemaking are recorded as regulatory assets on its consolidated balance sheets. Since the return to cost-of-service ratemaking, capital additions are recorded in utility plant. These classifications do not affect the rate-making treatment for these assets.

Estimated useful lives (authorized by the CPUC) and weighted-average useful lives of SCE's property, plant and equipment, are as follows:

	Estimated Useful Lives	Weighted-Average Useful Lives
Generation plant	39 years to 70 years	40 years
Distribution plant	30 years to 60 years	45 years
Transmission plant	35 years to 65 years	40 years
Other plant	5 years to 60 years	20 years

Nuclear fuel is recorded as utility plant in accordance with CPUC rate-making procedures.

Nonutility Property

Nonutility property, including construction in progress, is capitalized at cost, including interest accrued on borrowed funds that finance construction. Capitalized interest was less than a million in 2006, $16 million in 2005, and $9 million in 2004. Mountainview plant is included in nonutility property in accordance with the rate-making treatment. Capitalized interest is generally amortized over 30 years (the life of the purchase-power agreement under which Mountainview plant operates).

Depreciation and amortization is primarily computed on a straight-line basis over the estimated useful lives of nonutility properties. Depreciation expense stated as a percent of average original cost of depreciable nonutility property was, on a composite basis, 3.8% for 2006 and 3.6% for 2005. The composite rate for 2004 is not disclosed due to the noncomparability of this property in 2003. The VIEs (commenced consolidation in March 31, 2004) compose a majority of nonutility property.

Estimated useful lives for nonutility property are as follows:

Furniture and equipment	3 years to 20 years
Building, plant and equipment	5 years to 30 years
Land easements	60 years

Purchased Power

From January 17, 2001 to December 31, 2002, the CDWR purchased power on behalf of SCE's customers for SCE's residual net short power position (the amount of energy needed to serve SCE's customers in excess of SCE's own generation and purchased power contracts). Additionally, the CDWR signed long-term contracts that provide power for SCE's customers. Effective January 1, 2003, SCE resumed power procurement responsibilities for its residual net short position. SCE acts as a billing agent for the CDWR power, and any power purchased by the CDWR for delivery to SCE's customers is not considered a cost to SCE.

Receivables

SCE records an allowance for uncollectible accounts, as determined by the average percentage of amounts written-off in prior accounting periods. SCE assesses its customers a late fee of 0.9% per month, beginning 21 days after the bill is prepared. Inactive accounts are written off after 180 days.

Regulatory Assets and Liabilities

In accordance with SFAS No. 71, SCE records regulatory assets, which represent probable future recovery of certain costs from customers through the rate-making process, and regulatory liabilities, which represent probable future credits to customers through the rate-making process. See Note 11 for additional disclosures related to regulatory assets and liabilities.

Related Party Transactions

Four EME subsidiaries have 49% to 50% ownership in partnerships that sell electricity generated by their project facilities to SCE under long-term power purchase agreements with terms and pricing approved by the CPUC. Beginning March 31, 2004, SCE consolidates these projects. See Note 14 for further information regarding VIEs. These variable interest projects hold $26 million in long-term debt due to EME with an interest rate of 5%, due in April 2008. This is included in long-term debt on the consolidated balance sheet.

SCE holds $153 million in notes receivable from affiliates, due in June 2007 comprising of a $78 million note receivable from EME with an interest rate of London Interbank Offered Rate plus 0.275%; and a 4.4%, $75 million note receivable from Edison International. The $75 million note receivable was previously due from a subsidiary of Edison Capital and was transferred and assigned to Edison International in May 2006. Both notes receivable are included in receivables on the consolidated balance sheet.

Restricted Cash

SCE's restricted cash represents amounts used exclusively to make scheduled payments on the current maturities of rate reduction notes issued on behalf of SCE by a special purpose entity.

Revenue Recognition

Operating revenue is recognized as electricity is delivered and includes amounts for services rendered but unbilled at the end of each year. Amounts charged for services rendered are based on CPUC-authorized rates and FERC-approved rates, which provide an authorized rate of return, and recovery of operation and maintenance and capital-related carrying costs. CPUC rates are implemented upon approval, whereas FERC rates are implemented at the time when SCE files for a rate change with the FERC. Revenue collected prior to a final FERC decision is subject to refund. In accordance with SFAS No. 71, SCE recognizes revenue, subject to balancing account treatment, equal to the amount of actual costs incurred and up to its authorized revenue requirement. Any revenue collected in excess of actual costs incurred or above the authorized revenue requirement is not recognized as revenue and is deferred and recorded as regulatory liabilities. Costs incurred in excess of revenue billed are deferred in a balancing account and recorded as regulatory assets for recovery in future rates.

Since January 17, 2001, power purchased by the CDWR or through the ISO for SCE's customers is not considered a cost to SCE, because SCE is acting as an agent for these transactions. Further, amounts billed to ($2.5 billion in 2006, $1.9 billion in 2005 and $2.5 billion in 2004) and collected from SCE's customers for these power purchases, CDWR bond-related costs (effective November 15, 2002) and a portion of direct access exit fees (effective January 1, 2003) are being remitted to the CDWR and are not recognized as revenue by SCE.

Stock-Based Compensation

SCE's stock-based compensation plans primarily include the issuance of Edison International stock options and performance shares. Edison International usually does not issue new common stock for equity awards settled. Rather, a third party is used to facilitate the exercise of stock options and the purchase and delivery of outstanding common stock for settlement of performance shares. Edison International has approximately 13.5 million shares remaining for future issuance under its stock-based compensation plans, which are described more fully in "Stock-Based Compensation" in Note 5.

Prior to January 1, 2006, SCE accounted for these plans using the intrinsic value method. Upon grant, no stock-based compensation cost for stock options was reflected in net income, as the grant date was the measurement date, and all options granted under these plans had an exercise price equal to the market value of the underlying common stock on the date of grant. Previously, stock-based compensation cost for performance shares was remeasured at each reporting period and related compensation expense was adjusted. As discussed in "New Accounting Pronouncements" above, effective January 1, 2006, SCE implemented a new accounting standard that requires companies to use the fair value accounting method for stock-based compensation resulting in the recognition of expense for all stock-based compensation awards. SCE recognizes stock-based compensation expense on a straight-line basis over the requisite service period. Because SCE capitalizes a portion of cash-based compensation and SFAS No. 123(R) requires stock-based compensation to be recorded similarly to cash-based compensation, SCE capitalizes a portion of its stock-based compensation related to both unvested awards and new awards. SCE recognizes stock-based compensation expense for awards granted to retirement-eligible participants as follows: for stock-based awards granted prior to January 1, 2006, SCE recognized stock-based compensation expense over the explicit requisite service period and accelerated any remaining unrecognized compensation expense when a participant actually retired; for awards granted or modified after January 1, 2006, to participants who are retirement-eligible or will become retirement-eligible prior to the end of the normal requisite service period for the award, stock-based compensation will be recognized on a prorated basis over the initial year or over the period between the date of grant and the date the participant first becomes eligible for retirement. If SCE recognized stock-based compensation expense for awards granted prior to January 1, 2006, over a period to the date the participant first became eligible for retirement, stock-based compensation expense would have decreased by $4 million for 2006, would have increased $3 million for 2005 and would have increased $6 million for 2004.

Total stock-based compensation expense (reflected in the caption "other operation and maintenance" on the consolidated statements of income) was $33 million, $43 million and $46 million for 2006, 2005 and 2004, respectively. The income tax benefit recognized in the income statement was $13 million, $17 million and $19 million for 2006, 2005 and 2004, respectively. Total stock-based compensation cost capitalized was $6 million for 2006.

The following table illustrates the effect on net income available for common stock if SCE had used the fair-value accounting method for 2005 and 2004.

In millions Year ended December 31,	**2005**	2004
Net income available for common stock, as reported	**$ 725**	$ 915
Add: stock-based compensation expense using the intrinsic value accounting method – net of tax	**26**	28
Less: stock-based compensation expense using the fair-value accounting method – net of tax	**24**	32
Pro forma net income available for common stock	**$ 727**	$ 911

Note 2. Derivative Instruments and Hedging Activities

SCE recorded net unrealized gains (losses) of $(237) million, $90 million and $(9) million in 2006, 2005 and 2004, respectively, arising from derivative investments, which are reflected in purchased-power expense and offset through the provision for regulatory adjustment clauses—net on the consolidated statements of income.

Note 3. Liabilities and Lines of Credit

Long-Term Debt

Almost all SCE properties are subject to a trust indenture lien. SCE has pledged first and refunding mortgage bonds as collateral for borrowed funds obtained from pollution-control bonds issued by government agencies. SCE used these proceeds to finance construction of pollution-control facilities. SCE has a debt covenant that requires a debt to total capitalization ratio be met. At December 31, 2006, SCE was in compliance with this debt covenant. Bondholders have limited discretion in redeeming certain pollution-control bonds, and SCE has arranged with securities dealers to remarket or purchase them if necessary.

In December 1997, $2.5 billion of rate reduction notes were issued on behalf of SCE by SCE Funding LLC, a special purpose entity. These notes were issued to finance the 10% rate reduction mandated by state law. The proceeds of the rate reduction notes were used by SCE Funding LLC to purchase from SCE an enforceable right known as transition property. Transition property is a current property right created by the restructuring legislation and a financing order of the CPUC and consists generally of the right to be paid a specified amount from nonbypassable rates charged to residential and small commercial customers. The rate reduction notes are being repaid over 10 years through these nonbypassable residential and small commercial customer rates, which constitute the transition property purchased by SCE Funding LLC. The notes are scheduled to be paid off in December 2007 and the nonbypassable rates being charged to customers are expected to cease as of January 1, 2008. The notes are collateralized by the transition property and are not collateralized by, or payable from, assets of SCE or Edison International. SCE used the proceeds from the sale of the transition property to retire debt and equity securities. Although, as required by accounting principles generally accepted in the United States of America, SCE Funding LLC is consolidated with SCE and the rate reduction notes are shown as long-term debt in the consolidated financial statements, SCE Funding LLC is legally separate from SCE. The assets of SCE Funding LLC are not available to creditors of SCE or Edison International and the transition property is legally not an asset of SCE or Edison International.

Long-term debt is:

In millions December 31,	**2006**	2005
First and refunding mortgage bonds:		
2007 – 2037 (4.65% to 6.00% and variable)	**$ 3,525**	$ 2,775
Rate reduction notes:		
2007 (6.42%)	**246**	493
Pollution-control bonds:		
2015 – 2035 (2.9% to 5.55% and variable)	**1,196**	1,196
Debentures and notes:		
2008 – 2053 (5.00% to 7.625%)	**611**	810
Long-term debt due within one year	**(396)**	(596)
Unamortized debt discount – net	**(11)**	(9)
Total	**$ 5,171**	$ 4,669

Note: Rates and terms as of December 31, 2006

Long-term debt maturities and sinking-fund requirements for the next five years are: 2007 – $396 million; 2008 – $54 million; 2009 – $150 million; 2010 – $250 million; and 2011 – zero.

Short-Term Debt

There was no outstanding short-term debt at December 31, 2006 and 2005.

Lines of Credit

At December 31, 2006 and 2005 SCE had a credit line of $1.7 billion for both periods. At December 31, 2006, SCE had $1.54 billion in available credit under its credit line. At December 31, 2005, SCE had $1.52 billion in available credit under its credit line.

On February 23, 2007, SCE amended its credit facility, increasing the amount of borrowing capacity to $2.5 billion, extending the maturity to February 2012 and removing the first mortgage bond collateral pledge.

Preferred Stock Subject to Mandatory Redemption

At both December 31, 2006 and 2005, SCE had no preferred stock subject to mandatory redemption. At December 31, 2004, SCE's $100 par value cumulative preferred stock subject to mandatory redemption consisted of: $58 million (net of $9 million of preferred stock to be redeemed within one year) of preferred stock for Series 6.05% and $81 million for Series 7.23%.

The 6.05% Series preferred stock had mandatory sinking funds, requiring SCE to redeem at least 37,500 shares per year from 2003 through 2007, and 562,500 shares in 2008. SCE was allowed to credit previously repurchased shares against the mandatory sinking-fund provisions. In 2005, SCE redeemed 673,800 shares of 6.05% Series cumulative preferred stock, which included 36,300 shares redeemed to satisfy the mandatory sinking-fund requirement. In 2004, SCE repurchased 20,000 shares of 6.05% Series preferred stock. In 2003, SCE repurchased 56,200 shares of 6.05% Series preferred stock. At December 31, 2004, SCE had 1,200 previously repurchased, but not retired, shares available to credit against the mandatory sinking-fund provisions.

The 7.23% Series preferred stock also has mandatory sinking funds, requiring SCE to redeem at least 50,000 shares per year from 2002 through 2006, and 750,000 shares in 2007. However, SCE was allowed to credit previously repurchased shares against the mandatory sinking-fund provisions. In 2005, SCE redeemed the remaining 807,000 shares of 7.23% Series cumulative preferred stock. Since SCE had previously repurchased 193,000 shares of this series, no shares were redeemed in 2004 or

2003. At December 31, 2004, SCE had 43,000 previously repurchased, but not retired, shares available to credit against the mandatory sinking-fund provisions.

Note 4. Income Taxes

The components of income tax expense from continuing operations by location of taxing jurisdiction are:

In millions Year ended December 31	**2006**	2005	2004
Current:			
Federal	**$ 681**	$ 255	$ (88)
State	**159**	84	46
	840	339	(42)
Deferred:			
Federal	**(312)**	(18)	425
State	**(90)**	(29)	55
	(402)	(47)	480
Total	**$ 438**	$ 292	$ 438

The components of the net accumulated deferred income tax liability are:

In millions December 31,	**2006**	2005
Deferred tax assets:		
Accrued charges	**$ 59**	$ 117
Investment tax credits	**67**	72
Property-related	**408**	352
Regulatory balancing accounts	**496**	301
Unrealized gains and losses	**367**	321
Decommissioning	**167**	163
Pensions and PBOPs	**215**	182
Other	**358**	409
Total	**$ 2,137**	$ 1,917
Deferred tax liabilities:		
Property-related	**$ 3,166**	$ 3,184
Capitalized software costs	**147**	173
Regulatory balancing accounts	**393**	607
Unrealized gains and losses	**367**	321
Decommissioning	**140**	125
Other	**349**	327
Total	**$ 4,562**	$ 4,737
Accumulated deferred income taxes – net	**$ 2,425**	$ 2,820
Classification of accumulated deferred income taxes – net:		
Included in deferred credits and other liabilities	**$ 2,675**	$ 2,815
Included in total current assets	**250**	—
Included in total current liabilities	**—**	5

The federal statutory income tax rate is reconciled to the effective tax rate from continuing operations as follows:

Year ended December 31,	**2006**	2005	2004
Federal statutory rate	**35.0%**	35.0%	35.0%
Tax reserve adjustments	**3.1**	(2.1)	(7.3)
Resolution of state audit issue	**(3.9)**	—	—
Resolution of 1991-1993 audit cycle	**—**	(5.8)	—
Property-related	**(0.3)**	(0.5)	0.4
ESOP dividend payment	**(0.9)**	(1.0)	(0.6)
State tax – net of federal deduction	**3.6**	3.2	4.8
Other	**(2.0)**	(0.7)	(0.1)
Effective tax rate	**34.6%**	28.1%	32.2%

The composite federal and state statutory income tax rate was approximately 40% (net of the federal benefit for state income taxes) for all periods presented. The lower effective tax rate of 34.6% realized in 2006 was primarily due to a settlement reached with the California Franchise Tax Board regarding a state apportionment issue (See "Federal and State Income Taxes" in Note 6) partially offset by tax reserve accruals. The lower effective tax rate of 28.1% realized in 2005 was primarily due to settlement of the 1991-1993 IRS audit cycle as well as adjustments made to the tax reserve to reflect the issuance of new IRS regulations and the favorable settlement of other federal and state tax audit issues. The lower effective tax rate of 32.2% realized in 2004 was primarily due to adjustments to tax liabilities relating to prior years.

As a matter of course, SCE is regularly audited by federal and state taxing authorities. For further discussion of this matter, see "Federal and State Income Taxes" in Note 6.

Note 5. Compensation and Benefit Plans

Employee Savings Plan

SCE has a 401(k) defined contribution savings plan designed to supplement employees' retirement income. The plan received employer contributions of $57 million in 2006, $51 million in 2005 and $37 million in 2004.

Pension Plans and Postretirement Benefits Other Than Pensions

SFAS No. 158 requires companies to recognize the overfunded or underfunded status of a defined benefit pension plan and other postretirement plan as assets and/or liabilities in the balance sheet. The assets and/or liabilities are offset through other comprehensive income (loss) or by a regulatory asset or liability in the case of plans recoverable in utility rates (see "New Accounting Pronouncements" in Note 1). SCE adopted SFAS No. 158 as of December 31, 2006.

Pension Plans

Noncontributory defined benefit pension plans (some with cash balance features) cover most employees meeting minimum service requirements. SCE recognizes pension expense for its nonexecutive plan as calculated by the actuarial method used for ratemaking.

At December 31, 2005, the accumulated benefit obligations of the executive pension plans exceeded the related plan assets at the measurement dates. Prior to the adoption of SFAS No. 158, SCE's consolidated balance sheets included an additional minimum liability as required under the then-applicable accounting guidance, offset by charges to intangible assets and shareholders' equity (through a charge to accumulated other comprehensive income (loss)).

The expected contributions (all by the employer) are approximately $50 million for the year ended December 31, 2007. This amount is subject to change based on, among other things, the limits established for federal tax deductibility.

The fair value of the plan assets is determined by market value.

Information on plan assets and benefit obligations is shown below:

In millions Year ended December 31,	**2006**	2005
Change in projected benefit obligation		
Projected benefit obligation at beginning of year	**$ 3,222**	$ 3,033
Service cost	**102**	99
Interest cost	**169**	166
Amendments	**12**	2
Actuarial loss (gain)	**(66)**	103
Special termination benefits	**8**	—
Benefits paid	**(271)**	(181)
Projected benefit obligation at end of year	**$ 3,176**	$ 3,222
Accumulated benefit obligation at end of year	**$ 2,782**	$ 2,791
Change in plan assets		
Fair value of plan assets at beginning of year	**$ 3,103**	$ 2,981
Actual return on plan assets	**473**	297
Employer contributions	**35**	6
Benefits paid	**(271)**	(181)
Fair value of plan assets at end of year	**$ 3,340**	$ 3,103
Determination of net recorded asset		
Funded status	**$ 164**	$ (119)
Unrecognized net loss	**—**	113
Unrecognized prior service cost	**—**	76
Net recorded asset	**$ 164**	$ 70
Additional detail of amounts recognized in the consolidated balance sheets:		
Intangible asset	**$ —**	$ 2
Accumulated other comprehensive loss	**24**	19
Additional detail of amounts recognized in accumulated other comprehensive loss:		
Prior service cost	**$ 2**	—
Net actuarial loss	**22**	—
Additional detail of amounts recognized as a regulatory liability:		
Prior service cost	**$ 71**	—
Net actuarial loss (gain)	**(215)**	—
Pension plans with an accumulated benefit obligation in excess of plan assets:		
Projected benefit obligation	**$ 82**	$ 101
Accumulated benefit obligation	**67**	85
Fair value of plan assets	**—**	—
Weighted-average assumptions at end of year:		
Discount rate	**5.75%**	5.5%
Rate of compensation increase	**5.0%**	5.0%

Expense components are:

In millions Year ended December 31,	**2006**	2005	2004
Service cost	**$ 102**	$ 99	$ 86
Interest cost	**169**	166	162
Expected return on plan assets	**(225)**	(215)	(201)
Special termination benefits	**8**	—	—
Amortization of transition obligation	**—**	1	5
Amortization of unrecognized prior service cost	**16**	16	15
Amortization of unrecognized net loss	**3**	4	2
Expense under accounting standards	**73**	71	69
Regulatory adjustment – deferred	**(10)**	(26)	(26)
Total expense recognized	**$ 63**	$ 45	$ 43
Change in accumulated other comprehensive income (loss)	**$ (5)**	$ (3)	—
Weighted-average assumptions:			
Discount rate	**5.5%**	5.5%	6.0%
Rate of compensation increase	**5.0%**	5.0%	5.0%
Expected return on plan assets	**7.5%**	7.5%	7.5%

The estimated amortization amounts for 2007 are $17 million for prior service cost and $2 million for net actuarial loss.

Due to the Mohave shutdown, SCE has incurred costs for special termination benefits. For further information on Mohave, see Note 16.

The following benefit payments, which reflect expected future service, are expected to be paid:

In millions Year ended December 31,	
2007	$ 260
2008	273
2009	284
2010	294
2011	310
2012–2016	1,567

Asset allocations are:

	Target for 2007	December 31, **2006**	2005
United States equities	45%	**47%**	47%
Non-United States equities	25%	**26%**	26%
Private equities	4%	**2%**	2%
Fixed income	26%	**25%**	25%

Postretirement Benefits Other Than Pensions

Most nonunion employees retiring at or after age 55 with at least 10 years of service are eligible for postretirement health and dental care, life insurance and other benefits. Eligibility depends on a number of factors, including the employee's hire date.

On December 8, 2003, President Bush signed the Medicare Prescription Drug, Improvement and Modernization Act of 2003. The Act authorized a federal subsidy to be provided to plan sponsors for certain prescription drug benefits under Medicare. SCE adopted a new accounting pronouncement for the effects of the Act, effective July 1, 2004, which reduced Edison International's accumulated benefit obligation by $116 million upon adoption.

The expected contributions (all by the employer) to the PBOP trust are $41 million for the year ended December 31, 2007. This amount is subject to change based on, among other things, the limits established for federal tax deductibility.

The fair value of plan assets is determined by market value.

Information on plan assets and benefit obligations is shown below:

In millions Year ended December 31,	**2006**	2005
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 2,275**	$ 2,146
Service cost	**43**	44
Interest cost	**116**	118
Amendments	**—**	(15)
Actuarial loss (gain)	**(159)**	38
Special termination benefits	**4**	—
Plan participants' contributions	**7**	3
Medicare Part D subsidy received	**3**	—
Benefits paid	**(111)**	(59)
Benefit obligation at end of year	**$ 2,178**	$ 2,275
Change in plan assets		
Fair value of plan assets at beginning of year	**$ 1,573**	$ 1,465
Actual return on assets	**203**	92
Employer contributions	**68**	72
Plan participants' contributions	**7**	3
Medicare Part D subsidy received	**3**	—
Benefits paid	**(111)**	(59)
Fair value of plan assets at end of year	**$ 1,743**	$ 1,573
Determination of net recorded liability		
Funded status	**$ (435)**	$ (702)
Unrecognized net loss	**—**	842
Unrecognized prior service cost (credit)	**—**	(271)
Recorded asset (liability)	**$ (435)**	$ (131)
Additional detail of amounts recognized as a regulatory asset:		
Prior service cost (credit)	**$ (242)**	—
Net actuarial loss	**545**	—
Weighted-average assumptions at end of year:		
Discount rate	**5.75%**	5.5%
Assumed health care cost trend rates:		
Rate assumed for following year	**9.25%**	10.25%
Ultimate rate	**5.0%**	5.0%
Year ultimate rate reached	**2011**	2011

Expense components are:

In millions Year ended December 31,	**2006**	2005	2004
Service cost	**$ 43**	$ 44	$ 40
Interest cost	**116**	118	123
Expected return on plan assets	**(106)**	(101)	(96)
Special termination benefits	**4**	—	—
Amortization of unrecognized prior service cost (credit)	**(29)**	(28)	(29)
Amortization of unrecognized net loss	**41**	45	49
Total expense	**$ 69**	$ 78	$ 87
Weighted-average assumptions:			
Discount rate	**5.5%**	5.75%	6.25%
Expected return on plan assets	**7.0%**	7.1%	7.1%
Assumed health care cost trend rates:			
Current year	**10.25%**	10.0%	12.0%
Ultimate rate	**5.0%**	5.0%	5.0%
Year ultimate rate reached	**2011**	2010	2010

The estimated amortization amounts for 2007 are $(29) million for prior service cost (credit) and $25 million for net actuarial loss.

Due to the Mohave shutdown, SCE has incurred costs for special termination benefits. For further information on Mohave, see Note 16.

Increasing the health care cost trend rate by one percentage point would increase the accumulated benefit obligation as of December 31, 2006 by $267 million and annual aggregate service and interest costs by $18 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated benefit obligation as of December 31, 2006 by $238 million and annual aggregate service and interest costs by $16 million.

The following benefit payments are expected to be paid:

In millions Year ended December 31,	Before Subsidy	Net
2007	$ 100	$ 95
2008	100	95
2009	109	103
2010	118	112
2011	127	120
2012–2016	728	681

Asset allocations are:

	Target for 2007	December 31, **2006**	2005
United States equities	64%	**64%**	65%
Non-United States equities	16%	**13%**	14%
Fixed income	20%	**23%**	21%

Description of Pension and Postretirement Benefits Other Than Pensions Investment Strategies

The investment of plan assets is overseen by a fiduciary investment committee. Plan assets are invested using a combination of asset classes, and may have active and passive investment strategies within asset classes. SCE employs multiple investment management firms. Investment managers within each asset class cover a range of investment styles and approaches. Risk is controlled through diversification among multiple asset classes, managers, styles and securities. Plan, asset class and individual manager performance is measured against targets. SCE also monitors the stability of its investments managers' organizations.

Allowable investment types include:

United States Equities: Common and preferred stock of large, medium, and small companies which are predominantly United States-based.

Non-United States Equities: Equity securities issued by companies domiciled outside the United States and in depository receipts which represent ownership of securities of non-United States companies.

Private Equity: Limited partnerships that invest in nonpublicly traded entities.

Fixed Income: Fixed income securities issued or guaranteed by the United States government, non-United States governments, government agencies and instrumentalities, mortgage backed securities and corporate debt obligations. A small portion of the fixed income position may be held in debt securities that are below investment grade.

Permitted ranges around asset class portfolio weights are plus or minus 5%. Where approved by the fiduciary investment committee, futures contracts are used for portfolio rebalancing and to approach fully invested portfolio positions. Where authorized, a few of the plan's investment managers employ limited use of derivatives, including futures contracts, options, options on futures and interest rate swaps in place of direct investment in securities to gain efficient exposure to markets. Derivatives are not used to leverage the plans or any portfolios.

Determination of the Expected Long-Term Rate of Return on Assets for United States Plans

The overall expected long term rate of return on assets assumption is based on the target asset allocation for plan assets and capital markets return forecasts for asset classes employed. A portion of the PBOP trust asset returns are subject to taxation, so the expected long-term rate of return for these assets is determined on an after-tax basis.

Capital Markets Return Forecasts

The estimated total return for fixed income is based on an equilibrium yield for intermediate United States government bonds plus a premium for exposure to nongovernment bonds in the broad fixed income market. The equilibrium yield is based on analysis of historic data and is consistent with experience over various economic environments. The premium of the broad market over United States government bonds is a historic average premium. The estimated rate of return for equity is estimated to be a 3% premium over the estimated total return of intermediate United States government bonds. This value is determined by combining estimates of real earnings growth, dividend yields and inflation, each of which was determined using historical analysis. The rate of return for private equity is estimated to be a 5% premium over public equity, reflecting a premium for higher volatility and illiquidity.

Stock-Based Compensation

Stock Options

Under various plans, SCE may grant stock options at exercise prices equal to the average of the high and low price at the grant date and other awards related to or with a value derived from Edison International common stock to directors and certain employees. Options generally expire 10 years after the grant date and vest over a period of four years of continuous service, with expense recognized evenly over the requisite service period, except for awards granted to retirement-eligible participants, as discussed in "Stock-Based Compensation" in Note 1. Stock-based compensation expense associated with stock options (including amounts capitalized) was $24 million in 2006. Under prior accounting rules, there was no comparable expense recognized for the same period in 2005 and 2004. See "Stock-Based Compensation" in Note 1 for further discussion.

Beginning with awards made in 2003, stock options accrue dividend equivalents for the first five years of the option term. Unless transferred to nonqualified deferral plan accounts, dividend equivalents accumulate without interest. Dividend equivalents are paid only on options that vest, including options that are unexercised. Dividend equivalents are paid in cash after the vesting date. Edison International has discretion to pay certain dividend equivalents in shares of Edison International common stock. Additionally, Edison International will substitute cash awards to the extent necessary to pay tax withholding or any government levies.

The fair value for each option granted was determined as of the grant date using the Black-Scholes option-pricing model. The Black-Scholes option-pricing model requires various assumptions noted in the following table.

Year ended December 31,	**2006**	2005	2004
Expected terms (in years)	**9 to 10**	9 to 10	9 to 10
Risk-free interest rate	**4.3% – 4.7%**	4.1% – 4.3%	4.0% – 4.3%
Expected dividend yield	**2.3% – 2.8%**	2.1% – 3.1%	2.7% – 3.7%
Weighted-average expected dividend yield	**2.4%**	3.1%	3.6%
Expected volatility	**16% – 17%**	15% – 20%	19% – 22%
Weighted-average volatility	**16.3%**	19.5%	21.5%

The expected term of options granted is based on the actual remaining contractual term of the options. The risk-free interest rate for periods within the contractual life of the option is based on a 52-week historical average of the 10-year semi-annual coupon U.S. Treasury note. In 2006, expected volatility is based on the historical volatility of Edison International's common stock for the recent 36 months. Prior to January 1, 2006, expected volatility was based on the median of the most recent 36 months historical volatility of peer companies because Edison International's historical volatility was impacted by the California energy crisis.

A summary of the status of Edison International stock options granted to SCE employees is as follows:

		Weighted-Average		
	Stock Options	Exercise Price	Remaining Contractual Term (Years)	Aggregate Intrinsic Value
Outstanding at December 31, 2005	8,587,248	$ 23.22		
Granted	1,245,380	$ 44.10		
Expired	—	—		
Forfeited	(23,865)	$ 34.24		
Exercised	(2,047,427)	$ 22.12		
Outstanding at December 31, 2006	7,761,336	$ 26.78		
Vested and expected to vest at December 31, 2006	7,403,265	$ 26.56	6.36	$ 118,964,546
Exercisable at December 31, 2006	3,639,312	$ 22.06	4.85	$ 74,857,736

The weighted-average grant-date fair value of options granted during the 2006, 2005 and 2004 was $14.42, $11.76 and $8.25, respectively. The total intrinsic value of options exercised during 2006, 2005 and 2004 was $43 million, $42 million and $14 million, respectively. At December 31, 2006, there was $20 million of total unrecognized compensation cost related to stock options, net of expected forfeitures. That cost is expected to be recognized over a weighted-average period of approximately two years. The fair value of options vested during 2006, 2005, and 2004 was $27 million, $16 million and $11 million, respectively.

The amount of cash used to settle stock options exercised was $88 million, $95 million and $43 million for 2006, 2005, and 2004, respectively. Cash received from options exercised for 2006, 2005 and 2004 was $45 million, $53 million and $29 million, respectively. The estimated tax benefit from options exercised for 2006, 2005 and 2004 was $17 million, $17 million and $6 million.

In October 2001, a stock option retention exchange offer was extended, offering holders of Edison International stock options granted in 2000 the opportunity to exchange those options for a lesser number of deferred stock units, payable in shares of Edison International common stock. Approximately three options were cancelled for each deferred stock unit issued. The deferred stock units vested, and were settled, 25% in each of the ensuing 12-month periods. Cash used to settle deferred stock units in 2005 and 2004 was $11 million and $9 million, respectively.

Performance Shares

A target number of contingent performance shares were awarded to executives in January 2004, January 2005 and March 2006, and vest at the end of December 2006, 2007 and 2008, respectively. Dividend equivalents associated with these performance shares accumulate without interest and will be payable in cash following the end of the performance period when the performance shares are paid, although Edison International has discretion to pay certain dividend equivalents in Edison International common stock. The vesting of Edison International's performance shares is dependent upon a market condition and three years of continuous service subject to a prorated adjustment for employees who are terminated under certain circumstances or retire, but payment cannot be accelerated. The market condition is based on Edison International's common stock performance relative to the performance of a specified group of companies at the end of a three-calendar-year period. The number of performance shares earned is determined based on Edison International's ranking among these companies. Dividend equivalents will be adjusted to correlate to the actual number of performance shares paid. Performance shares earned are settled half in cash and half in common stock; however, Edison International has discretion under certain of the awards to pay the half subject to cash settlement in common stock. Additionally, cash awards are substituted to the extent necessary to pay tax withholding or any government levies. The portion of performance shares settled in cash is classified as a share-based liability award. The fair value of these shares is remeasured at each reporting period and the related compensation expense is adjusted. The portion of performance shares payable in common stock is classified as a share-based equity award. Compensation expense related to these shares is based on the grant-date fair value. Performance shares expense is recognized ratably over the requisite service period based on the fair values determined, except for awards granted to retirement-eligible participants, as discussed in "Stock-Based Compensation" in Note 1. Stock-based compensation expense associated with performance shares (including amounts capitalized) was $9 million, $31 million and $33 million for 2006, 2005, and 2004, respectively. The amount of cash used to settle performance shares classified as equity awards was $19 million, $10 million and $8 million for 2006, 2005 and 2004, respectively.

The performance shares' fair value is determined using a Monte Carlo simulation valuation model. The Monte Carlo simulation valuation model requires a risk-free interest rate and an expected volatility rate assumption. The risk-free interest rate is based on a 52-week historical average of the three-year semi-annual coupon U.S. Treasury note and is used as a proxy for the expected return for the specified group of companies. Volatility is based on the historical volatility of Edison International's common stock for the recent 36 months. Historical volatility for each company in the specified group is obtained from a financial data services provider.

Edison International's risk-free interest rate used to determine the grant date fair values for the 2006, 2005 and 2004 performance shares classified as share-based equity awards was 4.1%, 2.7% and 2.1%, respectively. Edison International's expected volatility used to determine the grant date fair values for the 2006, 2005 and 2004 performance shares classified as share-based equity awards was 16.2%, 27.7% and 36%, respectively. The portion of performance shares classified as share-based liability awards are revalued at each reporting period. The risk-free interest rate and expected volatility rate used to determine the fair value as of December 31, 2006 was 4.8% and 16.5%, respectively.

The total intrinsic value of performance shares settled during 2006, 2005 and 2004 was $38 million, $21 million and $4 million, respectively, which included cash paid to settle the performance shares classified as liability awards for 2006, 2005 and 2004 of $9 million, $5 million and $2 million, respectively. At December 31, 2006, there was $4 million (based on the December 31, 2006 fair value of performance shares classified as liability awards) of total unrecognized compensation cost related to performance shares. That cost is expected to be recognized over a weighted-average period of approximately one year. The fair values of performance shares vested during 2006, 2005 and 2004 was $14 million, $21 million and $13 million, respectively.

A summary of the status of Edison International nonvested performance shares granted to SCE employees and classified as equity awards is as follows:

	Performance Shares	Weighted-Average Grant Date Fair Value
Nonvested at December 31, 2005	146,280	$ 39.08
Granted	47,923	52.76
Forfeited	(2,018)	38.26
Paid out	(83,581)	33.99
Nonvested at December 31, 2006	108,604	$ 48.96

The weighted-average grant-date fair value of performance shares classified as equity awards granted during 2005 and 2004 was $46.09 and $33.62, respectively.

A summary of the status of Edison International nonvested performance shares granted to SCE employees and classified as liability awards (the current portion is reflected in the caption “Other current liabilities” and the long-term portion is reflected in “Accumulated provision for pensions and benefits” on the consolidated balance sheets) is as follows:

	Performance Shares	Weighted-Average Fair Value
Nonvested at December 31, 2005	146,400	
Granted	47,992	
Forfeited	(2,026)	
Paid out	(83,639)	
Nonvested at December 31, 2006	108,727	$ 48.58

Note 6. Commitments and Contingencies

Lease Commitments

In accordance with EITF No. 01-8, power contracts signed or modified after June 30, 2003, need to be assessed for lease accounting requirements. Unit specific contracts in which SCE takes virtually all of the output of a facility are generally considered to be leases. As of December 31, 2005, SCE had six power contracts classified as operating leases. In April 2006, SCE modified one power contract, and in November 2006 an additional 61 contracts were modified. The modifications to the contracts resulted in a change to the contractual terms of the contracts at which time SCE reassessed these power contracts under EITF No. 01-8 and determined that the contracts are leases and subsequently met the requirements for operating leases under SFAS No. 13. These power contracts had previously been grandfathered relative to EITF No. 01-8 and did not meet the normal purchases and sales exception. As a result, these contracts were recorded on the consolidated balance sheets at fair value in accordance with SFAS No. 133. The fair value changes for these power purchase contracts were previously recorded in purchased-power expense and offset through the provision for regulatory adjustment clauses—net ; therefore, fair value changes did not effect earnings. At the time of modification SCE had assets and liabilities related to mark-to-market gains or losses. Under SFAS No. 133, the assets and liabilities were reclassified to a lease prepayment or accrual and were included in the cost basis of the lease. The lease prepayment and accruals are being amortized over the life of the lease on a straight-line basis. At December 31, 2006, the net liability was $60 million. At December 31, 2006, SCE had 68 power contracts classified as operating leases. Operating lease expense for power purchases was $188 million in 2006, $68 million in 2005 and zero for 2004. In addition, SCE executed a power purchase contract in late 2005 which met the requirements for capital leases. The capital lease has a net commitment of $13 million at December 31, 2006. SCE's capital lease amortization expense and interest expense was $3 million in 2006.

Other operating lease expense, primarily for vehicle leases, was $31 million in 2006, $20 million in 2005 and $17 million in 2004. The leases have varying terms, provisions and expiration dates.

Estimated remaining commitments for noncancelable operating leases, including power purchases, vehicles, office space, and other equipment at December 31, 2006 are:

In millions	Year ended December 31,	Power Contracts Operating Leases	Other Operating Leases
2007		$ 579	$ 38
2008		556	36
2009		499	32
2010		463	27
2011		254	20
Thereafter		1,669	72
Total		$ 4,020	$ 225

As discussed above, SCE modified numerous power contracts which increased the noncancelable operating lease future commitments and decreased the power purchase commitments below in "Other Commitments."

Nuclear Decommissioning Commitment

SCE has collected in rates amounts for the future costs of removal of its nuclear assets, and has placed those amounts in independent trusts. The fair value of decommissioning SCE's nuclear power facilities is $2.7 billion as of December 31, 2006, based on site-specific studies performed in 2006 for San Onofre and Palo Verde. Changes in the estimated costs, timing of decommissioning, or the assumptions underlying these estimates could cause material revisions to the estimated total cost to decommission. SCE estimates that it will spend approximately $11.5 billion through 2049 to decommission its active nuclear facilities. This estimate is based on SCE's decommissioning cost methodology used for rate-making purposes, escalated at rates ranging from 1.7% to 7.5% (depending on the cost element) annually. These costs are expected to be funded from independent decommissioning trusts, which previously received contributions of $32 million effective October 2003. Effective January 2007, the amount allowed to be contributed to the trust increased to approximately $46 million per year. SCE estimates annual after-tax earnings on the decommissioning funds of 4.4% to 5.8%. If the assumed return on trust assets is not earned, it is probable that additional funds needed for decommissioning will be recoverable through rates in the future. If the assumed return on trust assets is greater than estimated, funding amounts may be reduced through future decommissioning proceedings.

Decommissioning of San Onofre Unit 1 is underway and will be completed in three phases: (1) decontamination and dismantling of all structures and some foundations; (2) spent fuel storage monitoring; and (3) fuel storage facility dismantling, removal of remaining foundations, and site restoration. Phase one is scheduled to continue through 2008. Phase two is expected to continue until 2026. Phase three will be conducted concurrently with the San Onofre Units 2 and 3 decommissioning projects. In February 2004, SCE announced that it discontinued plans to ship the San Onofre Unit 1 reactor pressure vessel to a disposal site until such time as appropriate arrangements are made for its permanent disposal. It will continue to be stored at its current location at San Onofre Unit 1. This action results in placing the disposal of the reactor pressure vessel in Phase three of the San Onofre Unit 1 decommissioning project.

All of SCE's San Onofre Unit 1 decommissioning costs will be paid from its nuclear decommissioning trust funds and are subject to CPUC review. The estimated remaining cost to decommission San Onofre Unit 1 is recorded as an ARO liability ($126 million at December 31, 2006). Total expenditures for the decommissioning of San Onofre Unit 1 were $468 million from the beginning of the project in 1998 through December 31, 2006.

Decommissioning expense under the rate-making method was $161 million in 2006, $118 million in 2005 and $125 million in 2004. The ARO for decommissioning SCE's active nuclear facilities was $2.6 billion at December 31, 2006 and $2.4 billion at December 31, 2005.

Decommissioning funds collected in rates are placed in independent trusts, which, together with accumulated earnings, will be utilized solely for decommissioning. The CPUC has set certain restrictions related to the investments of these trusts.

Trust investments (at fair value) include:

In millions	Maturity Dates	December 31,	**2006**	2005
Municipal bonds	2007 – 2047		**$ 692**	$ 863
Stocks	–		**1,611**	1,451
United States government issues	2007 – 2036		**729**	479
Corporate bonds	2007 – 2038		**104**	42
Short-term	2007		**48**	72
Total			**$ 3,184**	$ 2,907

Note: Maturity dates as of December 31, 2006.

Trust fund earnings (based on specific identification) increase the trust fund balance and the ARO regulatory liability. Net earnings were $130 million in 2006, $87 million in 2005 and $91 million in 2004. Proceeds from sales of securities (which are reinvested) were $3.0 billion in 2006, $2.0 billion in 2005 and $2.5 billion in 2004. Net unrealized holding gains were $1.04 billion and $852 million at December 31, 2006 and 2005, respectively. Realized losses for other-than-temporary impairments were $54 million for the year ended December 31, 2006. Approximately 91% of the cumulative trust fund contributions were tax-deductible.

Other Commitments

SCE has fuel supply contracts which require payment only if the fuel is made available for purchase. SCE has a coal fuel contract that requires payment of certain fixed charges whether or not coal is delivered.

SCE has power-purchase contracts with certain QFs (cogenerators and small power producers) and other power producers. These contracts provide for capacity payments if a facility meets certain performance obligations and energy payments based on actual power supplied to SCE (the energy payments are not included in the table below). There are no requirements to make debt-service payments. In an effort to replace higher-cost contract payments with lower-cost replacement power, SCE has entered into purchased-power settlements to end its contract obligations with certain QFs. The settlements are reported as power purchase contracts on the consolidated balance sheets.

Certain commitments for the years 2007 through 2011 are estimated below:

In millions	2007	2008	2009	2010	2011
Fuel supply	$ 75	$ 74	$ 51	$ 53	$ 54
Purchased power	481	255	144	134	112

SCE has an unconditional purchase obligation for firm transmission service from another utility. Minimum payments are based, in part, on the debt-service requirements of the transmission service provider, whether or not the transmission line is operable. The contract requires minimum payments of $57 million through 2016 (approximately $6 million per year).

Indemnities

In connection with the acquisition of Mountainview, SCE agreed to indemnify the seller with respect to specific environmental claims related to SCE's previously owned San Bernardino Generating Station, divested by SCE in 1998 and reacquired as part of the Mountainview acquisition. SCE retained certain responsibilities with respect to environmental claims as part of the original divestiture of the station. The aggregate liability for either party to the purchase agreement for damages and other amounts is a maximum of $60 million. This indemnification for environmental liabilities expires on or before March 12, 2033. SCE has not recorded a liability related to this indemnity.

SCE provides other indemnifications through contracts entered into in the normal course of business. These are primarily indemnifications against adverse litigation outcomes in connection with underwriting agreements, and specified environmental indemnities and income taxes with respect to assets sold. SCE's obligations under these agreements may be limited in terms of time and/or amount, and in some instances SCE may have recourse against third parties for certain indemnities. The obligated amounts of these indemnifications often are not explicitly stated, and the overall maximum amount of the obligation under these indemnifications cannot be reasonably estimated. SCE has not recorded a liability related to these indemnities.

Contingencies

In addition to the matters disclosed in these Notes, SCE is involved in other legal, tax and regulatory proceedings before various courts and governmental agencies regarding matters arising in the ordinary course of business. SCE believes the outcome of these other proceedings will not materially affect its results of operations or liquidity.

2006 GRC Proceeding

On May 11, 2006, the CPUC issued its final decision in SCE's 2006 GRC authorizing an increase of $274 million over SCE's 2005 base rate revenue, retroactive to January 12, 2006. When the one-time credit of $140 million from an existing balancing account overcollection was applied, SCE's authorized increase was $134 million. The CPUC also authorized increases of $74 million in 2007 and $104 million in 2008. The decision substantially approved SCE's request to continue its capital investment program for infrastructure replacement and expansion, with authorized revenue in excess of costs for this program subject to refund. In addition, the decision provided for balancing accounts for pensions, postretirement medical benefits and certain incentive compensation expense.

During the second quarter of 2006, SCE implemented the 2006 GRC decision and resolved an outstanding regulatory issue which resulted in a pre-tax benefit of approximately $175 million. The implementation of the 2006 GRC decision retroactive to January 12, 2006 mainly resulted in revenue of $50 million related to the revenue requirement for the period January 12, 2006 through May 31, 2006, partially offset by the implementation of the new depreciation rates resulting in increased depreciation expense of approximately $25 million for the period January 12, 2006 through May 31, 2006. In addition, there was a favorable resolution of a one-time issue related to a portion of revenue collected during the 2001–2003 period for state income taxes. SCE was able to determine through regulatory proceedings, including the 2006 GRC decision, that the level of revenue collected during that period was appropriate, and as a result recorded a pre-tax gain of $135 million.

Environmental Remediation

SCE is subject to numerous environmental laws and regulations, which require it to incur substantial costs to operate existing facilities, construct and operate new facilities, and mitigate or remove the effect of past operations on the environment.

SCE believes that it is in substantial compliance with environmental regulatory requirements; however, possible future developments, such as the enactment of more stringent environmental laws and regulations, could affect the costs and the manner in which business is conducted and could cause substantial additional capital expenditures. There is no assurance that additional costs would be recovered from customers or that SCE's financial position and results of operations would not be materially affected.

SCE records its environmental remediation liabilities when site assessments and/or remedial actions are probable and a range of reasonably likely cleanup costs can be estimated. SCE reviews its sites and measures the liability quarterly, by assessing a range of reasonably likely costs for each identified site using currently available information, including existing technology, presently enacted laws and regulations, experience gained at similar sites, and the probable level of involvement and financial condition of other potentially responsible parties. These estimates include costs for site investigations, remediation, operations and maintenance, monitoring and site closure. Unless there is a probable amount, SCE records the lower end of this reasonably likely range of costs (classified as other long-term liabilities) at undiscounted amounts.

SCE's recorded estimated minimum liability to remediate its 23 identified sites is $78 million. The ultimate costs to clean up SCE's identified sites may vary from its recorded liability due to numerous uncertainties inherent in the estimation process, such as: the extent and nature of contamination; the scarcity of reliable data for identified sites; the varying costs of alternative cleanup methods; developments resulting from investigatory studies; the possibility of identifying additional sites; and the time periods over which site remediation is expected to occur. SCE believes that, due to these uncertainties, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $123 million. The upper limit of this range of costs was estimated using assumptions least favorable to SCE among a range of reasonably possible outcomes. In addition to its identified sites (sites in which the upper end of the range of costs is at least $1 million), SCE also has 32 immaterial sites whose total liability ranges from $3 million (the recorded minimum liability) to $8 million.

The CPUC allows SCE to recover environmental remediation costs at certain sites, representing $31 million of its recorded liability, through an incentive mechanism (SCE may request to include additional sites). Under this mechanism, SCE will recover 90% of cleanup costs through customer rates; shareholders fund the remaining 10%, with the opportunity to recover these costs from insurance carriers and other third parties. SCE has successfully settled insurance claims with all responsible carriers. SCE expects to recover costs incurred at its remaining sites through customer rates. SCE has recorded a regulatory asset of $77 million for its estimated minimum environmental-cleanup costs expected to be recovered through customer rates.

SCE's identified sites include several sites for which there is a lack of currently available information, including the nature and magnitude of contamination and the extent, if any, that SCE may be held responsible for contributing to any costs incurred for remediating these sites. Thus, no reasonable estimate of cleanup costs can be made for these sites.

SCE expects to clean up its identified sites over a period of up to 30 years. Remediation costs in each of the next several years are expected to range from $11 million to $25 million. Recorded costs for the year ended December 31, 2006 were $14 million.

Based on currently available information, SCE believes it is unlikely that it will incur amounts in excess of the upper limit of the estimated range for its identified sites and, based upon the CPUC's regulatory treatment of environmental remediation costs, SCE believes that costs ultimately recorded will not materially affect its results of operations or financial position. There can be no assurance, however, that future developments, including additional information about existing sites or the identification of new sites, will not require material revisions to such estimates.

Federal and State Income Taxes

Edison International received Revenue Agent Reports from the IRS in August 2002 and in January 2005 asserting deficiencies in federal corporate income taxes with respect to audits of its 1994–1996 and 1997–1999 tax years, respectively. Many of the asserted tax deficiencies are timing differences and, therefore, amounts ultimately paid (exclusive of penalties), if any, would benefit SCE as future tax deductions. Edison International has also submitted affirmative claims to the IRS and state tax agencies which are being addressed in administrative proceedings. Any benefits would be recorded at the earlier of when Edison International believes that the affirmative claim position has a more likely than not probability of being sustained or when a settlement is reached. Certain affirmative claims may be recorded as part of the implementation of FIN 48.

The IRS Revenue Agent Report for the 1997–1999 audit also asserted deficiencies with respect to a transaction entered into by an SCE subsidiary which may be considered substantially similar to a listed transaction described by the IRS as a contingent liability company. While Edison International intends to defend its tax return position with respect to this transaction, the tax benefits relating to the capital loss deductions will not be claimed for financial accounting and reporting purposes until and unless these tax losses are sustained.

In April 2004, Edison International filed California Franchise Tax amended returns for tax years 1997 through 2002 to abate the possible imposition of new California penalty provisions on transactions that may be considered as listed or substantially similar to listed transactions described in an IRS notice that was published in 2001. These transactions include the SCE subsidiary contingent liability company transaction described above. Edison International filed these amended returns under protest retaining its appeal rights.

FERC Refund Proceedings

SCE is participating in several related proceedings seeking recovery of refunds from sellers of electricity and natural gas who manipulated the electric and natural gas markets during the energy crisis in California in 2000 – 2001 or who benefited from the manipulation by receiving inflated market prices. SCE is required to refund to customers 90% of any refunds actually realized by SCE, net of litigation costs, and 10% will be retained by SCE as a shareholder incentive.

During the course of the refund proceedings, the FERC ruled that governmental power sellers, like private generators and marketers that sold into the California market, should refund the excessive prices they received during the crisis period. However, on September 21, 2005, the Ninth Circuit ruled that the FERC does not have authority directly to enforce its refund orders against governmental power sellers. The Court, however, clarified that its decision does not preclude SCE or other parties from pursuing civil claims against the governmental power sellers. On March 16, 2006, SCE, PG&E and the California Electricity Oversight Board jointly filed suit in federal court against several governmental power sellers, seeking refunds based on the reduced prices set by the FERC for transactions during the crisis period. SCE cannot predict whether it may be able to recover any additional refunds from governmental power sellers as a result of this suit.

In November 2005, SCE and other parties entered into a settlement agreement with Enron Corporation and a number of its affiliates, most of which are debtors in Chapter 11 bankruptcy proceedings pending in New York. In April 2006, SCE received a distribution on its allowed bankruptcy claim of approximately $29 million, and 196,245 shares of common stock of Portland General Electric Company with an aggregate value of approximately $5 million. In October 2006, SCE received another distribution on its allowed bankruptcy claim of approximately $20 million and 17,040 shares of Portland General Electric Company stock, with an aggregate value of less than $1 million. Additional distributions are expected but SCE cannot currently predict the amount or timing of such distributions.

In December 2005, the FERC approved a settlement agreement among SCE, PG&E, SDG&E, several governmental entities and certain other parties, and Reliant Energy, Inc. and a number of its affiliates. In March 2006, SCE received $61 million as part of the consideration allocated to it under the settlement.

On August 2, 2006, the Ninth Circuit issued an opinion regarding the scope of refunds issued by the FERC. The Ninth Circuit broadened the time period during which refunds could be ordered to include the summer of 2000 based on evidence of pervasive tariff violations and broadened the categories of transactions that could be subject to refund. As a result of this decision, SCE may be able to recover additional refunds from sellers of electricity during the crisis with whom settlements have not been reached.

Investigations Regarding Performance Incentives Rewards

SCE was eligible under its CPUC-approved PBR mechanism to earn rewards or penalties based on its performance in comparison to CPUC-approved standards of customer satisfaction, employee injury and illness reporting, and system reliability.

SCE conducted investigations into its performance under these PBR mechanisms and has reported to the CPUC certain findings of misconduct and misreporting as further discussed below.

Customer Satisfaction

SCE received two letters in 2003 from one or more anonymous employees alleging that personnel in the service planning group of SCE's transmission and distribution business unit altered or omitted data in attempts to influence the outcome of customer satisfaction surveys conducted by an independent survey organization. The results of these surveys are used, along with other factors, to determine the amounts of any incentive rewards or penalties for customer satisfaction. SCE recorded aggregate customer satisfaction rewards of $28 million over the period 1997–2000. Potential customer satisfaction rewards aggregating $10 million for the years 2001 and 2002 are pending before the CPUC and have not been recognized in income by SCE. SCE also anticipated that it could be eligible for customer satisfaction rewards of approximately $10 million for 2003.

Following its internal investigation, SCE proposed to refund to ratepayers $7 million of the PBR rewards previously received and forgo an additional $5 million of the PBR rewards pending that are both attributable to the design organization's portion of the customer satisfaction rewards for the entire PBR period (1997–2003). In addition, SCE also proposed to refund all of the approximately $2 million of customer satisfaction rewards associated with meter reading.

SCE has taken remedial action as to the customer satisfaction survey misconduct by disciplining employees and/or terminating certain employees, including several supervisory personnel, updating system process and related documentation for survey reporting, and implementing additional supervisory controls over data collection and processing. Performance incentive rewards for customer satisfaction expired in 2003 pursuant to the 2003 GRC.

Employee Injury and Illness Reporting

In light of the problems uncovered with the customer satisfaction surveys, SCE conducted an investigation into the accuracy of SCE's employee injury and illness reporting. The yearly results of employee injury and illness reporting to the CPUC are used to determine the amount of the incentive reward or penalty to SCE under the PBR mechanism. Since the inception of PBR in 1997, SCE has recognized $20 million in employee safety incentives for 1997 through 2000 and, based on SCE's records, may be entitled to an additional $15 million for 2001 through 2003.

On October 21, 2004, SCE reported to the CPUC and other appropriate regulatory agencies certain findings concerning SCE's performance under the PBR incentive mechanism for injury and illness reporting. SCE disclosed in the investigative findings to the CPUC that SCE failed to implement an effective recordkeeping system sufficient to capture all required data for first aid incidents.

As a result of these findings, SCE proposed to the CPUC that it not collect any reward under the mechanism and return to ratepayers the $20 million it has already received. SCE has also proposed to withdraw the pending rewards for the 2001—2003 time frames.

SCE has taken remedial action to address the issues identified, including revising its organizational structure and overall program for environmental, health and safety compliance, disciplining employees who committed wrongdoing and terminating one employee. SCE submitted a report on the results of its investigation to the CPUC on December 3, 2004.

CPUC Investigation

On June 15, 2006, the CPUC instituted a formal investigation to determine whether and in what amounts to order refunds or disallowances of past and potential PBR rewards for customer satisfaction, employee safety, and system reliability portions of PBR. The CPUC also may consider whether to impose additional penalties on SCE.

In June 2006, the CPSD of the CPUC issued its report regarding SCE's PBR program, recommending that the CPUC impose various refunds and penalties on SCE. Subsequently, in September 2006, the CPSD and other intervenors, such as the CPUC's Division of Ratepayer Advocates and The Utility Reform Network filed testimony on these matters recommending various refunds and penalties to be imposed upon SCE. On October 16, 2006, SCE filed testimony opposing the various refund and penalty recommendations of the CPSD and other intervenors. Based on SCE's proposal for refunds and the combined recommendations of the CPSD and other intervenors, the potential refunds and penalties could range from $52 million up to $388 million. SCE has recorded an accrual at the lower end of this range of potential loss and is accruing interest on collected amounts that SCE has proposed to refund to customers. Evidentiary hearings which addressed the planning and meter reading components of customer satisfaction, safety, issues related to SCE's administration of the survey, and statutory fines associated with those matters took place in the fourth quarter of 2006. A schedule has not been set to address the other components of customer satisfaction, system reliability, and other issues in a second phase of the proceeding, although the CPSD has indicated its intent to complete a report by August 2007. A Presiding Officer's Decision is expected during the second quarter of 2007 on the issues addressed during phase one. At this time, SCE cannot predict the outcome of these matters or reasonably estimate the potential amount of any additional refunds, disallowances, or penalties that may be required above the lower end of the range.

ISO Disputed Charges

On April 20, 2004, the FERC issued an order concerning a dispute between the ISO and the Cities of Anaheim, Azusa, Banning, Colton and Riverside, California over the proper allocation and characterization of certain transmission service related charges. The order reversed an arbitrator's award that had affirmed the ISO's characterization in May 2000 of the charges as Intra-Zonal Congestion costs and allocation of those charges to scheduling coordinators in the affected zone within the ISO transmission grid. The April 20, 2004 order directed the ISO to shift the costs from scheduling coordinators in the affected zone to the responsible participating transmission owner, SCE. The potential cost to SCE, net of amounts SCE expects to receive through the PX, SCE's scheduling coordinator at the time, is estimated to be approximately $20 million to $25 million, including interest. On April 20, 2005, the FERC stayed its April 20, 2004 order during the pendency of SCE's appeal filed with the Court of Appeals for the D.C. Circuit. On March 7, 2006, the Court of Appeals remanded the case back to the FERC at the FERC's request and with SCE's consent. A decision is expected by March 2007. The FERC may require SCE to pay these costs, but SCE does not believe this outcome is probable. If SCE is required to pay these costs, SCE may seek recovery in its reliability service rates.

Midway-Sunset Cogeneration Company

San Joaquin Energy Company, a wholly owned subsidiary of EME, owns a 50% general partnership interest in Midway-Sunset, which owns a 225-MW cogeneration facility near Fellows, California. Midway-Sunset is a party to several proceedings pending at the FERC because Midway-Sunset was a seller in the PX and ISO markets during 2000 and 2001, both for its own account and on behalf of SCE and PG&E, the utilities to which the majority of Midway-Sunset's power was contracted for sale. As a seller into the PX and ISO markets, Midway-Sunset is potentially liable for refunds to purchasers in these markets. See discussion above in "FERC Refund Proceedings".

The claims asserted against Midway-Sunset for refunds related to power sold into the PX and ISO markets, including power sold on behalf of SCE and PG&E, are estimated to be less than $70 million for all periods under consideration. Midway-Sunset did not retain any proceeds from power sold into the PX and ISO markets on behalf of SCE and PG&E in excess of the amounts to which it was entitled under the pre-existing power sales contracts, but instead passed through those proceeds to the utilities. Since the proceeds were passed through to the utilities, EME believes that PG&E and SCE are obligated to reimburse Midway-Sunset for any refund liability that it incurs as a result of sales made into the PX and ISO markets on their behalves.

During this period, amounts SCE received from Midway-Sunset were credited to SCE's customers against power purchase expenses through the ratemaking mechanism in place at that time. SCE believes that any net amounts reimbursed to Midway-Sunset would be substantially recoverable from its customers through current regulatory mechanisms. SCE does not expect any reimbursement to Midway-Sunset to have a material impact on earnings.

Navajo Nation Litigation

The Navajo Nation filed a complaint in June 1999 in the District Court, against SCE, among other defendants, arising out of the coal supply agreement for Mohave. The complaint asserts claims for, among other things, violations of the federal RICO statute, interference with fiduciary duties and contractual relations, fraudulent misrepresentations by nondisclosure, and various contract-related claims. The complaint claims that the defendants' actions prevented the Navajo Nation from obtaining the full value in royalty rates for the coal supplied to Mohave. The complaint seeks damages of not less than $600 million, trebling of that amount, and punitive damages of not less than $1 billion.

In April 2004, the District Court dismissed SCE's motion for summary judgment and concluded that a 2003 U.S. Supreme Court decision in an on-going related lawsuit by the Navajo Nation against the U.S. Government did not preclude the Navajo Nation from pursuing its RICO and intentional tort claims.

Pursuant to a joint request of the parties, the District Court granted a stay of the action on October 5, 2004 to allow the parties to attempt to negotiate a resolution of the issues associated with Mohave with the assistance of a facilitator. An initial organizational session was held with the facilitator on

October 14, 2004 and negotiations are on-going. On July 28, 2005, the District Court issued an order removing the case from its active calendar, subject to reinstatement at the request of any party.

SCE cannot predict the outcome of the 1999 Navajo Nation's complaint against SCE, the ultimate impact on the complaint of the Supreme Court's 2003 decision and the on-going litigation by the Navajo Nation against the Government in the related case, or the impact on the facilitated negotiations of the Mohave co-owners' announced decisions to discontinue efforts to return Mohave to service.

Nuclear Insurance

Federal law limits public liability claims from a nuclear incident to $10.8 billion. SCE and other owners of San Onofre and Palo Verde have purchased the maximum private primary insurance available ($300 million). The balance is covered by the industry's retrospective rating plan that uses deferred premium charges to every reactor licensee if a nuclear incident at any licensed reactor in the United States results in claims and/or costs which exceed the primary insurance at that plant site. Federal regulations require this secondary level of financial protection. The NRC exempted San Onofre Unit 1 from this secondary level, effective June 1994. The current maximum deferred premium for each nuclear incident is $101 million per reactor, but not more than $15 million per reactor may be charged in any one year for each incident. The maximum deferred premium per reactor and the yearly assessment per reactor for each nuclear incident will be adjusted for inflation on a 5-year schedule. The next inflation adjustment will occur no later than August 20, 2008. Based on its ownership interests, SCE could be required to pay a maximum of $201 million per nuclear incident. However, it would have to pay no more than $30 million per incident in any one year. Such amounts include a 5% surcharge if additional funds are needed to satisfy public liability claims and are subject to adjustment for inflation. If the public liability limit above is insufficient, federal regulations may impose further revenue-raising measures to pay claims, including a possible additional assessment on all licensed reactor operators.

Property damage insurance covers losses up to $500 million, including decontamination costs, at San Onofre and Palo Verde. Decontamination liability and property damage coverage exceeding the primary $500 million also has been purchased in amounts greater than federal requirements. Additional insurance covers part of replacement power expenses during an accident-related nuclear unit outage. A mutual insurance company owned by utilities with nuclear facilities issues these policies. If losses at any nuclear facility covered by the arrangement were to exceed the accumulated funds for these insurance programs, SCE could be assessed retrospective premium adjustments of up to $42 million per year. Insurance premiums are charged to operating expense.

Procurement of Renewable Resources

California law requires SCE to increase its procurement of renewable resources by at least 1% of its annual retail electricity sales per year so that 20% of its annual electricity sales are procured from renewable resources by no later than December 31, 2010.

SCE entered into a contract with Calpine Energy Services, L.P. to purchase the output of certain existing geothermal facilities in northern California. Under previous CPUC decisions and reporting and compliance methodology, SCE was only able to count procurement pursuant to the Calpine contract towards its annual renewable target to the extent the output was certified as "incremental" by the CEC. On October 19, 2006, the CPUC issued a decision that revised the reporting and compliance methodology, and permitted SCE to count the entire output under the Calpine contract towards satisfaction of its annual renewable procurement target thus meeting its renewable procurement obligations for 2003, 2004, 2005 and 2006. The decision also implemented a "cumulative deficit banking" feature which would carry forward and accumulate annual deficits until the deficit has been satisfied at a later time through actual deliveries of eligible renewable energy.

Under the new methodology, SCE could have deficits in meeting its renewable procurement obligations for 2007 and beyond. However, based on California law, SCE has challenged the CPUC's accounting determination that defines the annual targets for each year of the renewables portfolio standards program. A change in the CPUC's accounting methodology in response to this challenge would enable SCE to meet its target for 2007 and possibly later years. At this time, SCE cannot predict the outcome of its challenge. Regardless of the CPUC's decision on SCE's challenge, SCE believes it may be able to demonstrate that it should not be penalized for any deficit.

Under current CPUC decisions, potential penalties for SCE's failure to achieve its renewable procurement objectives for any year will be considered by the CPUC in the context of the CPUC's review of SCE's annual compliance filing. Under the CPUC's current rules, the maximum penalty for failing to achieve renewable procurement targets is $25 million per year. SCE cannot predict whether it will be assessed penalties.

Scheduling Coordinator Tariff Dispute

Pursuant to the Amended and Restated Exchange Agreement, SCE serves as a scheduling coordinator for the DWP over the ISO-controlled grid. In late 2003, SCE began charging the DWP under a tariff subject to refund for FERC-authorized scheduling coordinator charges incurred by SCE on the DWP's behalf. The scheduling coordinator charges are billed to the DWP under a FERC tariff that remains subject to dispute. The DWP has paid the amounts billed under protest but requested that the FERC declare that SCE was obligated to serve as the DWP's scheduling coordinator without charge. The FERC accepted SCE's tariff for filing, but held that the rates charged to the DWP have not been shown to be just and reasonable and thus made them subject to refund and further review by the FERC. As a result, SCE could be required to refund all or part of the amounts collected from the DWP under the tariff. As of December 31, 2006, SCE has accrued a $41 million charge to earnings for the potential refunds. SCE and DWP have entered into a term sheet that would settle this dispute, among others surrounding the Exchange Agreement. If the settlement is effectuated, SCE would refund to DWP the scheduling coordinator charges collected, with an offset for losses, subject to being able to recover the scheduling coordinator charges from all transmission grid customers through another regulatory mechanism. The parties are currently negotiating the exact terms of the settlement.

Settlement Agreement with Duke Energy Trading and Marketing, LLC

On September 21, 2006, the CPUC approved a settlement agreement between SCE and Duke that resolved disputes arising from Duke's termination of certain bilateral power supply contracts in early 2001. Under the settlement, Duke made a $77 million principal and interest payment to SCE in October 2006, which will be refunded to ratepayers through the ERRA mechanism. The settlement also permitted $58 million in liabilities that SCE had previously recorded with respect to the Duke terminated contracts to be reversed, which resulted in an equivalent benefit recorded by SCE in the third quarter of 2006. The CPUC agreed that these liabilities should not be refunded to ratepayers. The recorded liabilities consisted of $40 million in cash collateral received from Duke in 2000 and $18 million in power purchase payments that SCE, in light of Duke's termination of the bilateral contracts, withheld for energy delivered by Duke in January 2001.

Spent Nuclear Fuel

Under federal law, the DOE is responsible for the selection and construction of a facility for the permanent disposal of spent nuclear fuel and high-level radioactive waste. The DOE did not meet its obligation to begin acceptance of spent nuclear fuel not later than January 31, 1998. It is not certain when the DOE will begin accepting spent nuclear fuel from San Onofre or other nuclear power plants. Extended delays by the DOE have led to the construction of costly alternatives and associated siting and environmental issues. SCE has paid the DOE the required one-time fee applicable to nuclear generation at San Onofre through April 6, 1983 (approximately $24 million, plus interest). SCE is also paying the required quarterly fee equal to 0.1¢-per-kWh of nuclear-generated electricity sold after April 6, 1983. On January 29, 2004, SCE, as operating agent, filed a complaint against the DOE in the United States Court of Federal Claims seeking damages for the DOE's failure to meet its obligation to begin accepting spent nuclear fuel from San Onofre. The case was stayed through April 7, 2006, when SCE and the DOE filed a Joint Status Report in which SCE sought to lift the stay and the government opposed lifting the stay. On June 5, 2006, the Court of Federal Claims lifted the stay on SCE's case and established a discovery schedule. A Joint Status Report is due on September 7, 2007, regarding further proceedings in this case and presumably including establishing a trial date.

SCE has primary responsibility for the interim storage of spent nuclear fuel generated at San Onofre. Spent nuclear fuel is stored in the San Onofre Units 2 and 3 spent fuel pools and the San Onofre independent spent fuel storage installation where all of Unit 1's spent fuel located at San Onofre is stored. There is now sufficient space in the Unit 2 and 3 spent fuel pools to meet plant requirements through mid-2007 and mid-2008, respectively. In order to maintain a full core off-load capability, SCE began moving Unit 2 spent fuel into the independent spent fuel storage installation in late February 2007.

There are now sufficient dry casks and modules available to the independent spent fuel storage installation to meet plant requirements through 2008. SCE, as operating agent, plans to continually load casks on a schedule to maintain full core off-load capability for both units in order to meet the plant requirements after 2008 until 2022 (the end of the current NRC operating license).

In order to increase on-site storage capacity and maintain core off-load capability, Palo Verde has constructed an independent spent fuel storage facility. Arizona Public Service, as operating agent, plans to continually load dry casks on a schedule to maintain full core off-load capability for all three units.

Note 7. Accumulated Other Comprehensive Loss Information

Supplemental information regarding SCE's accumulated other comprehensive loss is:

In millions December 31,	**2006**	2005
Minimum pension liability – net of tax	**$ —**	$ (11)
SFAS No. 158 – Postretirement benefits – net of tax	**(14)**	—
Unrealized losses on cash flow hedges – net of tax	**—**	(5)
Accumulated other comprehensive loss	**$ (14)**	$ (16)

SFAS No. 158 – postretirement benefits is discussed in "Pension Plans and Postretirement Benefits Other Than Pensions" in Note 5. The unrealized losses on cash flow hedges in 2005 related to SCE's interest rate swap. The swap terminated on January 5, 2001 and the related debt originally matured in 2008. This debt was redeemed in April 2006. The remaining balance of $4 million as of April 2006, net of tax, is no longer reflected in accumulated other comprehensive loss.

Note 8. Property and Plant

Nonutility property included in the consolidated balance sheets is comprised of:

In millions December 31,	**2006**	2005
Furniture and equipment	**$ 4**	$ 3
Building, plant and equipment	**1,639**	1,347
Land (including easements)	**34**	34
Construction in progress	**2**	271
	1,679	1,655
Accumulated provision for depreciation	**(633)**	(569)
Nonutility property – net	**$ 1,046**	$ 1,086

Asset Retirement Obligations

As a result of the adoption of SFAS No. 143 in 2003, SCE recorded the fair value of its liability for legal AROs, which was primarily related to the decommissioning of its nuclear power facilities. In addition, SCE capitalized the initial costs of the ARO into a nuclear-related ARO regulatory asset, and also recorded an ARO regulatory liability as a result of timing differences between the recognition of costs recorded in accordance with the standard and the recovery of the related asset retirement costs through the rate-making process. SCE has collected in rates amounts for the future costs of removal of its nuclear assets, and has placed those amounts in independent trusts.

A reconciliation of the changes in the ARO liability is as follows:

In millions	**2006**	2005	2004
Beginning balance	**$ 2,621**	$ 2,183	$ 2,084
Accretion expense	**160**	366	132
Revisions	**(3)**	117	—
Liabilities added	**41**	14	—
Liabilities settled	**(70)**	(59)	(33)
Ending balance	**$ 2,749**	$ 2,621	$ 2,183

The fair value of the nuclear decommissioning trusts was $3.2 billion at December 31, 2006. For a further discussion about nuclear decommissioning trusts see "Nuclear Decommissioning Commitment" in Note 6.

In March 2005, the FASB issued FIN 47, which clarifies that an entity is required to recognize a liability for the fair value of a conditional ARO if the fair value can be reasonably estimated even though uncertainty exists about the timing and/or method of settlement. FIN 47 was effective as of December 31, 2005. Since SCE follows SFAS No. 71 and receives recovery of these costs through rates; therefore, SCE's implementation of FIN 47 did not affect SCE's earnings. The pro forma disclosures related to adoption of FIN 47 are not shown due to the immaterial impact on SCE's consolidated balance sheet.

Note 9. Supplemental Cash Flows Information

SCE supplemental cash flows information is:

In millions Year ended December 31,	**2006**	2005	2004
Cash payments for interest and taxes:			
Interest – net of amounts capitalized	**$ 321**	$ 330	$ 342
Tax payments – net	**832**	410	29
Noncash investing and financing activities:			
Details of debt exchange:			
Pollution-control bonds redeemed	**$ (331)**	$ (452)	—
Pollution-control bonds issued	**331**	452	—
Details of obligation under capital lease:			
Capital lease purchased	**—**	$ (15)	—
Capital lease obligation issued	**—**	15	—
Dividends declared but not paid	**$ 69**	$ 81	—
Details of consolidation of variable interest entities:			
Assets	**—**	—	$ 458
Liabilities	**—**	—	(537)
Reoffering of pollution-control bonds	**—**	—	196
Details of pollution-control bonds redemption:			
Release of funds held in trust	**—**	—	$ 20
Pollution-control bonds redeemed	**—**	—	(20)

Note 10. Fair Values of Financial Instruments

The carrying amounts and fair values of financial instruments are:

	December 31,			
	2006		2005	
In millions	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Derivatives:				
Commodity price assets	**$ 50**	**$ 50**	$ 239	$ 239
Commodity price liabilities	**(160)**	**(160)**	(87)	(87)
Other:				
Decommissioning trusts	**3,184**	**3,184**	2,907	2,907
DOE decommissioning and decontamination fees	**—**	**—**	(7)	(7)
QF power contracts assets	**—**	**—**	23	23
QF power contracts liabilities	**(2)**	**(2)**	(94)	(94)
Long-term debt	**(5,171)**	**(5,206)**	(4,669)	(4,812)
Long-term debt due within one year	**(396)**	**(398)**	(596)	(604)

Fair values are based on: brokers' quotes for interest rate hedges, long-term debt and preferred stock; financial models for commodity price derivatives and QF power contracts; quoted market prices for decommissioning trusts; and discounted future cash flows for DOE decommissioning and decontamination fees.

Due to their short maturities, amounts reported for cash equivalents approximate fair value.

Note 11. Regulatory Assets and Liabilities

Included in SCE's regulatory assets and liabilities are regulatory balancing accounts. Sales balancing accounts accumulate differences between recorded revenue and revenue SCE is authorized to collect through rates. Cost balancing accounts accumulate differences between recorded costs and costs SCE is authorized to recover through rates. Undercollections are recorded as regulatory balancing account assets. Overcollections are recorded as regulatory balancing account liabilities. SCE's regulatory balancing accounts accumulate balances until they are refunded to or received from SCE's customers through authorized rate adjustments. Primarily all of SCE's balancing accounts can be classified as one of the following types: generation-revenue related, distribution-revenue related, generation-cost related, distribution-cost related, transmission-cost related or public purpose and other cost related.

Balancing account undercollections and overcollections accrue interest based on a three-month commercial paper rate published by the Federal Reserve. Income tax effects on all balancing account changes are deferred.

Amounts included in regulatory assets and liabilities are generally recorded with corresponding offsets to the applicable income statement accounts, except for regulatory balancing accounts, which are offset through the "Provisions for regulatory adjustments clauses – net" account.

Regulatory Assets

Regulatory assets included on the consolidated balance sheets are:

In millions December 31,	**2006**	2005
Current:		
Regulatory balancing accounts	**$ 128**	$ 355
Rate reduction notes – transition cost deferral	**219**	—
Direct access procurement charges	**63**	113
Energy derivatives	**88**	—
Purchased-power settlements	**31**	53
Other	**25**	15
	554	536
Long-term:		
Flow-through taxes – net	**1,023**	1,066
Rate reduction notes – transition cost deferral	**—**	465
Unamortized nuclear investment – net	**435**	487
Nuclear-related ARO investment – net	**317**	292
Unamortized coal plant investment – net	**102**	97
Unamortized loss on reacquired debt	**318**	323
Direct access procurement charges	**—**	40
SFAS No. 158 pensions and other postretirement benefits	**303**	—
Energy derivatives	**145**	58
Environmental remediation	**77**	56
Purchased-power settlements	**8**	39
Other	**90**	90
	2,818	3,013
Total Regulatory Assets	**$ 3,372**	$ 3,549

SCE's regulatory asset related to the rate reduction bonds is amortized simultaneously with the amortization of the rate reduction bonds liability, and is expected to be recovered by the end of 2007. SCE's regulatory assets related to direct access procurement charges are for amounts direct access customers owe bundled service customers for the period May 1, 2000 through August 31, 2001, and are offset by corresponding regulatory liabilities to the bundled service customers. These amounts will be collected by late 2007. SCE's regulatory assets related to energy derivatives are an offset to unrealized losses on recorded derivatives and an offset to lease accruals. SCE's regulatory assets related to purchased-power settlements will be recovered through 2008. Based on current regulatory ratemaking and income tax laws, SCE expects to recover its net regulatory assets related to flow-through taxes over the life of the assets that give rise to the accumulated deferred income taxes. SCE's nuclear-related regulatory assets are expected to be recovered by the end of the remaining useful lives of the nuclear facilities. SCE's net regulatory asset related to its unamortized coal plant investment is being recovered through June 2016. SCE's net regulatory asset related to its unamortized loss on reacquired debt will be recovered over the remaining original amortization period of the reacquired debt over periods ranging from one year to 28 years. SCE's regulatory asset related to SFAS No. 158 represents the offset to the additional amounts recorded in accordance with SFAS No. 158 (see "Pension Plans and Postretirement Benefits Other Than Pensions" discussion in Note 5). This amount will be recovered through rates charged to customers. SCE's regulatory asset related to environmental remediation represents the portion of SCE's environmental liability recognized at the end of the period in excess of the amount that has been recovered through rates charged to customers. This amount will be recovered in future rates as expenditures are made.

SCE earns a return on three of the regulatory assets listed above: unamortized nuclear investment – net, unamortized coal plant investment – net and unamortized loss on reacquired debt.

Regulatory Liabilities

Regulatory liabilities included on the consolidated balance sheets are:

In millions December 31,	**2006**	2005
Current:		
Regulatory balancing accounts	**$ 912**	$ 370
Direct access procurement charges	**63**	113
Energy derivatives	**7**	136
Other	**18**	62
	1,000	681
Long-term:		
ARO	**732**	584
Costs of removal	**2,158**	2,110
SFAS No. 158 pensions and other postretirement benefits	**145**	—
Direct access procurement charges	**—**	39
Energy derivatives	**27**	—
Employee benefit plans	**78**	229
	3,140	2,962
Total Regulatory Liabilities	**$ 4,140**	$ 3,643

SCE's regulatory liabilities related to direct access procurement charges are a liability to its bundled service customers and are offset by regulatory assets from direct access customers. SCE's regulatory liabilities related to energy derivatives are an offset to unrealized gains on recorded derivatives and an offset to a lease prepayment. SCE's regulatory liability related to the ARO represents timing differences between the recognition of AROs in accordance with generally accepted accounting principles and the amounts recognized for rate-making purposes. SCE's regulatory liabilities related to costs of removal represent revenue collected for asset removal costs that SCE expects to incur in the future. SCE's regulatory liability related to SFAS No. 158 represents the offset to the additional amounts recorded in accordance with SFAS No. 158 (see "Pension Plans and Postretirement Benefits Other Than Pensions" discussion in Note 5). This amount will be returned to ratepayers in some future rate-making proceeding. SCE's regulatory liabilities related to employee benefit plan expenses represent pension costs recovered through rates charged to customers in excess of the amounts recognized as expense or the difference between these costs calculated in accordance with rate-making methods and these costs calculated in accordance with SFAS No. 87, Employers' Accounting for

Pensions, and PBOP costs recovered through rates charged to customers in excess of the amounts recognized as expense. These balances will be returned to ratepayers in some future rate-making proceeding, be charged against expense to the extent that future expenses exceed amounts recoverable through the rate-making process, or be applied as otherwise directed by the CPUC.

Note 12. Other Nonoperating Income and Deductions

Other nonoperating income and deductions are as follows:

In millions Year ended December 31,	**2006**	2005	2004
AFUDC	**$ 32**	$ 25	$ 35
Performance-based incentive awards	**19**	33	31
Demand-side management and energy efficiency performance incentives	**—**	45	—
Other	**34**	24	18
Total other nonoperating income	**$ 85**	$ 127	$ 84
Various penalties	**$ 23**	$ 27	$ 35
Other	**37**	38	34
Total other nonoperating deductions	**$ 60**	$ 65	$ 69

Note 13. Jointly Owned Utility Projects

SCE owns interests in several generating stations and transmission systems for which each participant provides its own financing. SCE's proportionate share of expenses for each project is included in the consolidated statements of income.

SCE's investment in each project as of December 31, 2006 is:

In millions	Investment in Facility	Accumulated Depreciation and Amortization	Ownership Interest
Transmission systems:			
Eldorado	$ 72	$ 11	60%
Pacific Intertie	308	92	50
Generating stations:			
Four Corners Units 4 and 5 (coal)	506	421	48
Mohave (coal)	352	279	56
Palo Verde (nuclear)	1,746	1,477	16
San Onofre (nuclear)	4,612	3,971	78
Total	$ 7,596	$ 6,251	

All of Mohave Generating Station and a portion of San Onofre and Palo Verde is included in regulatory assets on the consolidated balance sheets – see Note 11. Mohave ceased operations on December 31, 2005. For further information on Mohave see Note 16. In December 2006, SCE acquired the City of Anaheim's approximately 3% ownership interest of San Onofre Units 2 and 3.

Note 14. Variable Interest Entities

SCE has variable interests in contracts with certain QFs that contain variable contract pricing provisions based on the price of natural gas. Four of these contracts are with entities that are partnerships owned in part by a related party, EME. These four contracts had 20-year terms at inception. The QFs sell electricity to SCE and steam to nonrelated parties. Under a new accounting standard, SCE consolidated these four projects effective March 31, 2004. Prior periods have not been restated.

Project	Capacity	Termination Date	EME Ownership
Kern River	295 MW	June 2011	50%
Midway-Sunset	225 MW	May 2009	50%
Sycamore	300 MW	December 2007	50%
Watson	385 MW	December 2007	49%

SCE has no investment in, nor obligation to provide support to, these entities other than its requirement to make contract payments. Any profit or loss generated by these entities will not effect SCE's income statement, except that SCE would be required to recognize losses if these projects have negative equity in the future. These losses, if any, would not affect SCE's liquidity. Any liabilities of these projects are nonrecourse to SCE.

Effective April 1, 2004, the VIEs' operating costs are shown in SCE's consolidated statements of income. Prior to that date, purchases under these QF contracts were reported as purchased-power expense. Further, SCE's operating revenue beginning April 1, 2004, includes revenue from the sale of steam by these four projects. The effect that these VIEs have on SCE's consolidated financial statements is shown in Note 10.

SCE also has eight other contracts with QFs that contain variable pricing provisions based on the price of natural gas and are potential VIEs. SCE might be considered to be the consolidating entity under the new accounting standard. However, these entities are not legally obligated to provide the financial information to SCE that is necessary to determine whether SCE must consolidate these entities. These eight entities have declined to provide SCE with the necessary financial information. SCE is continuing to attempt to obtain information for these projects in order to determine whether they should be consolidated by SCE. The aggregate capacity dedicated to SCE for these projects is 267 MW. SCE paid $180 million in 2006 , $198 million in 2005 and $166 million in 2004 to these projects. These amounts are recoverable in utility customer rates. SCE has no exposure to loss as a result of its involvement with these projects.

Note 15. Preferred and Preference Stock Not Subject to Mandatory Redemption

SCE's authorized shares are: $100 cumulative preferred – 12 million shares, $25 cumulative preferred – 24 million shares and preference – 50 million shares. There are no dividends in arrears for the preferred stock or preference shares. Shares of SCE's preferred stock have liquidation and dividend preferences over shares of SCE's common stock and preference stock. All cumulative preferred stock is redeemable. When preferred shares are redeemed, the premiums paid, if any, are charged to common equity. No preferred stock not subject to mandatory redemption was issued or redeemed in the last three years. There is no sinking fund redemption or repurchase of the preferred stock.

Shares of SCE's preference stock rank junior to all of the preferred stock and senior to all common stock. Shares of SCE's preference stock are not convertible into shares of any other class or series of SCE's capital stock or any other security. The preference shares are noncumulative and have a $100 liquidation value. There is no sinking fund for the redemption or repurchase of the preference shares.

Preferred stock and preference stock not subject to mandatory redemption is:

Dollars in millions, except per-share amounts	December 31, 2006 Shares Outstanding	December 31, 2006 Redemption Price	**2006**	2005
Cumulative preferred stock:				
$25 par value:				
4.08% Series	1,000,000	$ 25.50	**$ 25**	$ 25
4.24	1,200,000	25.80	**30**	30
4.32	1,653,429	28.75	**41**	41
4.78	1,296,769	25.80	**33**	33
Preference stock:				
No par value:				
5.349% Series A	4,000,000	100.00	**400**	400
6.125% Series B	2,000,000	100.00	**200**	200
6.00% Series C	2,000,000	100.00	**200**	—
Total			**$ 929**	$ 729

The Series A preference stock, issued in 2005, may not be redeemed prior to April 30, 2010. After April 30, 2010, SCE may, at its option, redeem the shares in whole or in part and the dividend rate may be adjusted. The Series B preference stock, issued in 2005, may not be redeemed prior to September 30, 2010. After September 30, 2010, SCE may, at its option, redeem the shares in whole or in part. The Series C preference stock, issued in 2006, may not be redeemed prior to January 31, 2011. After, January 31, 2011, SCE may, at its option, redeem the shares in whole or in part. No preference stock not subject to mandatory redemption was redeemed in the last three years.

Note 16. Mohave Shutdown

Mohave obtained all of its coal supply from the Black Mesa Mine in northeast Arizona, located on lands of the Tribes. This coal was delivered from the mine to Mohave by means of a coal slurry pipeline, which required water from wells located on lands belonging to the Tribes in the mine vicinity. Uncertainty over post-2005 coal and water supply has prevented SCE and other Mohave co-owners from making approximately $1.1 billion in Mohave-related investments (SCE's share is $605 million), including the installation of enhanced pollution-control equipment required by a 1999 air-quality consent decree in order for Mohave to operate beyond 2005. Accordingly, the plant ceased operations, as scheduled, on December 31, 2005, consistent with the provisions of the consent decree.

On June 19, 2006, SCE announced that it had decided not to move forward with its efforts to return Mohave to service. SCE's decision was not based on any one factor, but resulted from the conclusion that in light of all the significant unresolved challenges related to returning the plant to service, the plant could not be returned to service in sufficient time to render the necessary investments cost-effective for SCE's customers. Two of the other Mohave co-owners, Nevada Power Company and the DWP, made similar announcements, while the fourth co-owner, SRP, has announced that it is pursuing the possibility of putting together a successor owner group, which would include SRP, to pursue continued coal operations. On February 6, 2007, however, SRP issued a press release announcing that it was discontinuing its efforts to return Mohave to service. All of the co-owners are continuing to evaluate the range of options for disposition of the plant, which conceivably could include, among other potential options, sale of the plant "as is" to a power plant operator, decommissioning and sale of the property to a developer, and decommissioning and apportionment of the land among the owners. At this time, SCE continues to work with the water and coal suppliers to the plant to determine if more clarity around the provision of such services can be provided to any potential acquirer.

Following the suspension of Mohave operations at the end of 2005, the plant's workforce was reduced from over 300 employees to approximately 65 employees by the end of 2006. SCE recorded $15 million in termination costs during the year for Mohave (SCE's share). These termination costs were deferred in a balancing account authorized in the 2006 GRC decision. SCE expects to recover this amount in the balancing account in future rate-making proceedings.

As of December 31, 2006, SCE had a Mohave net regulatory asset of approximately $81 million representing its net unamortized coal plant investment, partially offset by revenue collected for future removal costs. Based on the 2006 GRC decision, SCE is allowed to continue to earn its authorized rate of return on the Mohave investment and receive rate recovery for amortization, costs of removal, and operating and maintenance expenses, subject to balancing account treatment, during the three-year 2006 rate case cycle. On October 5, 2006, SCE submitted a formal notification to the CPUC regarding the out-of-service status of Mohave, pursuant to a California statute requiring such notice to the CPUC whenever a plant has been out of service for nine consecutive months. SCE also reported to the CPUC on Mohave's status numerous times previously. Pursuant to the statute, the CPUC may institute an investigation to determine whether to reduce SCE's rates in light of Mohave's changed status. At this time, SCE does not anticipate that the CPUC will order a rate reduction. In the past, the CPUC has allowed full recovery of investment for similarly situated plants. However, in a December 2004 decision, the CPUC noted that SCE would not be allowed to recover any unamortized plant balances if SCE could not demonstrate that it took all steps to preserve the "Mohave-open" alternative. SCE believes that it will be able to demonstrate that SCE did everything reasonably possible to return Mohave to service, which it further believes would permit its unamortized costs to be recovered in future rates. However, SCE cannot predict the outcome of any future CPUC action.

Note 17. Business Segments

SCE's reportable business segments include the rate-regulated electric utility segment and the VIE segment. The VIEs were consolidated as of March 31, 2004. The VIEs are gas-fired power plants that sell both electricity and steam. The VIE segment consists of non-rate-regulated entities. SCE's management has no control over the resources allocated to the VIE segment and does not make decisions about its performance. Additional details on the VIE segment are shown under the heading "Variable Interest Entities" in Note 14.

SCE's business segment information including all line items with VIE activities is:

In millions	Electric Utility	VIEs	Eliminations	SCE
Balance Sheet Items as of December 31, 2006:				
Cash and equivalents	$ 5	$ 78	$ —	$ 83
Accounts receivable–net	893	141	(95)	939
Inventory	218	14	—	232
Other current assets	50	4	—	54
Nonutility property–net of depreciation	727	319	—	1,046
Other long-term assets	481	7	—	488
Total assets	25,642	563	(95)	26,110
Accounts payable	809	142	(95)	856
Other current liabilities	622	2	—	624
Long-term debt	5,117	54	—	5,171
Asset retirement obligations	2,735	14	—	2,749
Minority interest	—	351	—	351
Total liabilities and shareholder's equity	$ 25,642	$ 563	$ (95)	$ 26,110
Balance Sheet Items as of December 31, 2005:				
Cash	$ 23	$ 120	$ —	$ 143
Accounts receivable–net	794	174	(119)	849
Inventory	202	18	—	220
Other current assets	88	4	—	92
Nonutility property–net of depreciation	741	345	—	1,086
Other long-term assets	493	10	—	503
Total assets	24,151	671	(119)	24,703
Accounts payable	813	204	(119)	898
Other current liabilities	721	2	—	723
Long-term debt	4,615	54	—	4,669
Asset retirement obligations	2,608	13	—	2,621
Minority interest	—	398	—	398
Total liabilities and shareholder's equity	$ 24,151	$ 671	$ (119)	$ 24,703

In millions	Electric Utility	VIEs	Eliminations*	SCE
Income Statement Items for the Year-Ended December 31, 2006:				
Operating revenue	$ 9,926	$ 1,137	$ (751)	$ 10,312
Fuel	389	723	—	1,112
Purchased power	4,160	—	(751)	3,409
Other operation and maintenance	2,575	103	—	2,678
Depreciation, decommissioning and amortization	990	36	—	1,026
Total operating expenses	8,344	862	(751)	8,455
Operating income	1,582	275	—	1,857
Interest income	58	—	—	58
Interest expense – net of amounts capitalized	400	—	—	400
Income tax expense	438	—	—	438
Minority interest	—	275	—	275
Net income	$ 827	—	—	$ 827
Income Statement Items for the Year-Ended December 31, 2005:				
Operating revenue	$ 9,038	$ 1,397	$ (935)	$ 9,500
Fuel	269	924	—	1,193
Purchased power	3,557	—	(935)	2,622
Other operation and maintenance	2,421	102	—	2,523
Depreciation, decommissioning and amortization	878	37	—	915
Total operating expenses	7,743	1,063	(935)	7,871
Operating income	1,295	334	—	1,629
Interest income	44	—	—	44
Interest expense – net of amounts capitalized	360	—	—	360
Income tax expense	292	—	—	292
Minority interest	—	334	—	334
Net income	$ 749	—	—	$ 749
Income Statement Items for the Year-Ended December 31, 2004:				
Operating revenue	$ 8,163	$ 954	$ (669)	$ 8,448
Fuel	232	578	—	810
Purchased power	3,001	—	(669)	2,332
Other operation and maintenance	2,389	68	—	2,457
Depreciation, decommissioning and amortization	832	28	—	860
Total operating expenses	6,430	674	(669)	6,435
Operating income	1,733	280	—	2,013
Interest income	20	—	—	20
Interest expense – net of amounts capitalized	409	—	—	409
Income tax expense	438	—	—	438
Minority interest	—	280	—	280
Net income	$ 921	—	—	$ 921

* VIE segment revenue includes sales to the electric utility segment, which is eliminated in revenue and purchased power in the consolidated statements of income.

Note 18. Acquisitions

In March 2004, SCE acquired Mountainview Power Company LLC, which consisted of a power plant in early stages of construction in Redlands, California. SCE recommenced full construction of the approximately $600 million project. The Mountainview plant is fully operational.

Note 19. Quarterly Financial Data (Unaudited)

In millions	**2006** Total(1)	**Fourth**	**Third**	**Second**	**First**	2005 Total(1)	Fourth	Third	Second	First
Operating revenue	**$ 10,312**	**$ 2,494**	**$ 3,079**	**$ 2,521**	**$ 2,217**	$ 9,500	$ 2,306	$ 3,084	$ 2,203	$ 1,908
Operating income	**1,857**	**315**	**673**	**536**	**332**	1,629	345	568	388	328
Net income	**827**	**171**	**276**	**247**	**133**	749	163	287	166	132
Net income available for common stock	**776**	**158**	**263**	**234**	**121**	725	153	280	161	131
Common dividends declared	**240**	**60**	**60**	**60**	**60**	285	71	143	71	—

(1) As a result of rounding, the total of the four quarters does not always equal the amount for the year.

Dollars in millions	**2006**	2005	2004	2003	2002
Income statement data:					
Operating revenue	**$ 10,312**	$ 9,500	$ 8,448	$ 8,854	$ 8,706
Operating expenses	**8,455**	7,871	6,435	7,276	6,588
Purchased-power expenses	**3,409**	2,622	2,332	2,786	2,016
Income tax expense	**438**	292	438	388	642
Provisions for regulatory adjustment clauses – net	**25**	435	(201)	1,138	1,502
Interest expense – net of amounts capitalized	**400**	360	409	457	584
Net income from continuing operations	**827**	749	921	882	1,247
Net income	**827**	749	921	932	1,247
Net income available for common stock	**776**	725	915	922	1,228
Ratio of earnings to fixed charges	**3.98**	3.79	4.40	3.80	4.20
Balance sheet data:					
Assets	**$ 26,110**	$ 24,703	$ 23,290	$ 21,771	$ 36,058
Gross utility plant	**20,734**	19,232	17,981	16,991	16,232
Accumulated provision for depreciation and decommissioning	**4,821**	4,763	4,506	4,386	4,057
Short-term debt	**—**	—	88	200	—
Common shareholder's equity	**5,447**	4,930	4,521	4,355	4,384
Preferred and preference stock:					
Not subject to mandatory redemption	**929**	729	129	129	129
Subject to mandatory redemption	**—**	—	139	141	147
Long-term debt	**5,171**	4,669	5,225	4,121	4,525
Capital structure:					
Common shareholder's equity	**47.2%**	47.7%	45.1%	49.8%	47.7%
Preferred stock:					
Not subject to mandatory redemption	**8.0%**	7.1%	1.3%	1.5%	1.4%
Subject to mandatory redemption		—	1.4%	1.6%	1.6%
Long-term debt	**44.8%**	45.2%	52.2%	47.1%	49.3%

The selected financial data was derived form SCE's audited financial statements and is qualified in its entirety by the more detailed information and financial statements, including notes to these financial statements, included in this annual report.

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Chairman of the Board, Southern
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A director from 1990-1999;
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2 Compensation and Executive Personnel Committee
3 Executive Committee
4 Finance Committee
5 Nominating/Corporate Governance Committee
6 Pricing Committee
7 Pricing Committee (Alternate Member)

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Technical Services

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Kenneth S. Stewart
Vice President and
Chief Ethics and Compliance Officer

Linda G. Sullivan
Vice President and
Controller

Raymond W. Waldo
Vice President,
Nuclear Generation

Shareholder Information

Annual Meeting

The annual meeting of shareholders will be held on Thursday, April 26, 2007, at 10:00 a.m., Pacific Time, at the Pacific Palms Conference Resort; One Industry Hills Parkway, City of Industry, California 91744.

Corporate Governance Practices

A description of SCE's corporate governance practices is available on our Web site at www.edisoninvestor.com. The SCE Board Nominating/Corporate Governance Committee periodically reviews the Company's corporate governance practices and makes recommendations to the Company's Board that the practices be updated from time to time.

Stock and Trading Information

Preferred Stock and Preference Stock
SCE's 4.08%, 4.24%, 4.32% and 4.78% Series of $25 par value cumulative preferred stock are listed on the American Stock Exchange. Previous day's closing prices, when stock was traded, are listed in the daily newspapers under the American Stock Exchange. Shares of SCE's Series A, Series B and Series C preference stock are not listed on an exchange.

Transfer Agent and Registrar

Wells Fargo Bank, N.A., which maintains shareholder records, is the transfer agent and registrar for SCE's preferred and preference stock. Shareholders may call Wells Fargo Shareowner Services, (800) 347-8625, between 7 a.m. and 7 p.m. (Central Time), Monday through Friday, to speak with a representative (or to use the interactive voice response unit 24 hours a day, seven days a week) regarding:

- stock transfer and name-change requirements;
- address changes, including dividend payment addresses;
- electronic deposit of dividends;
- taxpayer identification number submissions or changes;
- duplicate 1099 and W-9 forms;
- notices of, and replacement of, lost or destroyed stock certificates and dividend checks; and
- requests for access to online account information.

Inquiries may also be directed to:

Mail
Wells Fargo Bank, N.A.
Shareowner Services Department
161 North Concord Exchange Street
South St. Paul, MN 55075-1139

Fax
(651) 450-4033
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