EDISON INTERNATIONAL

2000 *Annual Report*

Edison International

Edison International, based in Rosemead, California, is the holding company of Southern California Edison Company, Edison Mission Energy, Edison Capital and Edison Enterprises. Through its subsidiaries, it is an international electric power generator, distributor and structured finance provider.

Edison International's operating companies have offices throughout California, as well as in Boston, Chicago, New York, Washington D.C., Australia, Indonesia, Italy, the Philippines, Singapore, Spain, Turkey and the United Kingdom.

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April 16, 2001

Dear Fellow Shareholders:

As you know, this has been a very difficult year for our company. Overshadowing everything we have accomplished over the last several years, the California power crisis has pushed Southern California Edison (SCE) to the edge of bankruptcy.

Early last summer, the cost of unregulated wholesale power in California rose sharply, moving above the revenues allowed in regulated retail rates to make such purchases. Under utility law, electric utilities purchase wholesale power as a service to their customers but are not allowed any profit for such procurement. They are, however, entitled to recover the full costs of this procurement service in retail customer rates.

Beginning last May, SCE had to borrow heavily to raise cash for wholesale power purchases necessary to keep electricity flowing to our customers. Through the fall, the California Public Utilities Commission (CPUC) took no action on our requests for a rate increase until January 4 of this year, and when it finally acted, the commission granted only a small increase — far below what was necessary to keep us creditworthy.

With that, lenders lost faith in California regulation and both Pacific Gas and Electric Company, our utility neighbor to the north, and Southern California Edison were unable to borrow further. By mid-January, SCE had to stop making payments to procure new power and to stop paying existing creditors. From that point forward, the major challenge of providing reliable power under tight supply conditions spiraled into a full-fledged crisis. Power generators sought to avoid sales in California, large risk premiums were added to wholesale prices, and the State of California went into the procurement business at massive cost to the state treasury. Compounding the problem, natural gas prices soared throughout the winter — greatly increasing fuel costs for power generation, and precipitation was below normal in both the Pacific Northwest and California, promising reduced availability of hydropower.

Throughout this time, Southern California Edison employees persevered under tough conditions, continuing to maintain good service and a reliable power grid for delivery of available supplies while intensely seeking to find a path toward restored creditworthiness.

On April 6, Pacific Gas and Electric Company filed for bankruptcy. On April 9, after two months of intense negotiations, we finally reached a detailed Memorandum of Understanding with California Gov. Gray Davis, charting a path to financial health for SCE. Under the terms of the agreement, SCE will play a substantial role in helping restore stability and reliability to the California electric system.

The Memorandum of Understanding with the governor and the California Department of Water Resources provides for SCE to generate cash to pay off past power procurement undercollections through the sale of bonds, which would be serviced by less than one half cent per kilowatt hour in customer rates and through a gain on the sale of SCE's transmission system to the State of California. SCE would commit to capital investment of at least $3 billion over the next five years in its utility infrastructure to assure a reliable power grid for transportation of power to customers, and to maintain and enhance SCE's remaining power generation fleet.

Further, Edison Mission Energy (EME) would sell the output of a new natural gas-fired power project in Kern County, California, to the state under a cost-based 10-year contract. The agreement also provides for other benefits for the state and actions to allow SCE to return to an investment-grade credit rating. When it is fully implemented, SCE has agreed to drop its filed rate doctrine lawsuit, which seeks a judgment from a federal court that SCE is entitled to recover its past power procurement undercollections.

Taken as a whole, the agreement is preferable to the financial and time costs of multiple litigations and bankruptcy. Both the CPUC and the state legislature must take actions to make effective the plan developed in the Memorandum of Understanding. It is in the best interest of the state, as well as our company and our customers, that the regulators and legislators act with a sense of urgency. Only a healthy utility can make the necessary investments and provide the experience and skill to maintain a reliable power grid in this most challenging of times.

With respect to our nonutility businesses, their credit has also been adversely impacted by uncertainties at the utility. The credit rating at our Edison International holding company has fallen below investment grade. EME continues to develop its independent power generation business which, as a result of the California supply problem, is recognized in most U.S. markets as important. EME has also made progress in its international operations, but continues to face a poor power market in the United Kingdom. Growth at our other subsidiaries will be constrained until greater stability is achieved at SCE. Edison Capital, in particular, will make no new investments until our credit position is stablized, and will sell some existing investments in order to improve its liquidity position.

As you know, in December and again last month, we were forced to suspend Edison International common stock dividends and defer SCE preferred dividends, as cash preservation measures. The California power crisis marks the first time in more than 100 years as a business that we have had to take this drastic action, and we deeply regret it.

No privately owned utility can make the large capital investments necessary to build and maintain a reliable electric system without fairly rewarding the investors who make the business possible. We are focused on rewarding our shareholders and attach great importance to retaining the loyal shareholders who provide Edison with great stability and strength. SCE will make every effort to resume preferred shareholder dividends and restore common dividends as soon as practicable. We are also intent on paying as soon as possible our creditors who have also shown much-appreciated forbearance.

Throughout the crisis, our employees and our Board of Directors have consistently demonstrated dedication, resolve, commitment and professionalism in the face of formidable challenges. I want to extend my appreciation to each of them, and to you, our shareholders. Working together, we have charted and can complete a viable course out of the crisis for our fine company to weather the storm, to rebuild and to grow.

John E. Bryson
Chairman, President and CEO
Edison International

California's investor-owned electric utilities, including Southern California Edison Company (SCE), are currently facing a crisis resulting from deregulation of the generation side of the electric industry through legislation enacted by the California Legislature and decisions issued by the California Public Utilities Commission (CPUC). Under the legislation and CPUC decisions, prices for wholesale purchases of electricity from power suppliers are set by markets while the retail prices paid by utility customers for electricity delivered to them remain frozen at June 1996 levels. Since May 2000, SCE's costs to obtain power (at wholesale electricity prices) for resale to its customers substantially exceeded revenue from frozen rates. The shortfall has been accumulated in the transition revenue account (TRA), a CPUC-authorized regulatory asset. SCE has borrowed significant amounts of money to finance its electricity purchases, creating a severe financial drain on SCE.

On April 9, 2001, Edison International, SCE and the California Department of Water Resources (CDWR) executed a memorandum of understanding (MOU) which sets forth a comprehensive plan calling for legislation, regulatory action and definitive agreements to resolve important aspects of the energy crisis, and which is expected to help restore SCE's creditworthiness and liquidity. The Governor of the State of California and his representatives participated in the negotiation of the MOU, and the Governor endorsed implementation of all the elements of the MOU. The MOU is discussed in detail in the Memorandum of Understanding with the CDWR section. Edison International, SCE and the CDWR committed in the MOU to proceed in good faith to sponsor and support the required legislation and to negotiate in good faith the necessary definitive agreements. If required legislation is not adopted and definitive agreements executed by August 15, 2001, or if the CPUC does not adopt required implementing decisions by June 8, 2001, the MOU may be terminated by Edison International, SCE or the CDWR. Neither Edison International nor SCE can provide assurance that all the required legislation will be enacted, regulatory actions taken and definitive agreements executed before the applicable deadlines.

Accounting standards generally accepted in the United States permit SCE to defer costs as regulatory assets if those costs are determined to be probable of recovery in future rates. If SCE determines that regulatory assets, such as the TRA and the transition cost balancing account (TCBA), are no longer probable of recovery through future rates, they must be written off. The TCBA is a regulatory balancing account that tracks the recovery of generation-related transition costs, including stranded investments. SCE must assess the probability of recovery of the undercollected costs that are now recorded in the TCBA in light of the CPUC's March 27, 2001, and April 3, 2001, decisions, including the retroactive transfer of balances from SCE's TRA to its TCBA and related changes that are discussed in more detail in Rate Stabilization Proceeding. These decisions and other regulatory and legislative actions did not meet SCE's prior expectation that the CPUC would provide adequate cost recovery mechanisms. Until legislative and regulatory actions contemplated by the MOU occur, or other actions are taken, SCE is unable to conclude that its undercollected costs that are recovered through the TCBA mechanism are probable of recovery in future rates. As a result, Edison International's financial results for the year ended 2000 include an after-tax charge at SCE of approximately $2.5 billion ($4.2 billion on a pre-tax basis), reflecting a write-off of the TCBA (as restated to reflect the CPUC's March 27, 2001, decisions) and regulatory assets to be recovered through the TCBA mechanism, as of December 31, 2000. In addition, SCE currently does not have regulatory authority to recover any purchased-power costs it incurs during 2001 in excess of revenue from retail rates. Those amounts will be charged against earnings in 2001 absent a regulatory or legislative solution, such as implementation of the actions called for in the MOU that makes recovery of such costs probable. This will result in further material declines in reported common shareholders' equity, particularly in light of the CPUC's failure to provide SCE with sufficient rate revenue to cover its ongoing costs and obligations through the CPUC's March 27, 2001, decisions. The December 31, 2000, write-off also caused SCE to be unable to meet an earnings test that must be met before SCE can issue additional first mortgage bonds. If the MOU is implemented, or a rate mechanism provided by legislation or regulatory authority is established that makes recovery from regulated rates probable as to all or a portion of the amounts that were previously charged against earnings, current accounting standards provide that a regulatory asset would be reinstated with a corresponding increase in earnings.

The following pages include a discussion of the history of the TRA and TCBA and related circumstances, the devastating effect on the financial condition of SCE of undercollections recorded in the TRA and TCBA, the current status of the undercollections, the impact of the CPUC's March 27, 2001, decisions and related matters, and possible resolution of the current crisis through implementation of the MOU.

Results of Operations

Earnings

In 2000, Edison International recorded a loss of $5.84 per share. The net loss in 2000 included a write-off at SCE of regulatory assets and liabilities in the amount of $2.5 billion (after tax), or $7.58 per share as of December 31, 2000. Accounting principles generally accepted in the United States require SCE at each financial statement date to assess the probability of recovering its regulatory assets through a regulatory process. On March 27, 2001, the CPUC issued a decision adopting a 3¢-per-kilowatt-hour (kWh) surcharge on rates effective immediately, with revenue generated by the surcharge to be applied to electric power costs incurred after the date of the order. This rate stabilization decision also stated that the rate freeze had not ended, and the TCBA mechanism was to remain in place. However, the decision required SCE to recalculate the TCBA retroactive to January 1, 1998, the beginning of the rate freeze period. The new calculation required the coal and hydroelectric balancing accounting overcollections (which amounted to $1.5 billion as of December 31, 2000) to be closed monthly to the TRA, rather than annually to the TCBA. In addition, it required the TRA to be transferred to the TCBA on a monthly basis. Previous rules had called for TRA overcollections to be transferred to the TCBA monthly, while undercollections were to remain in the TRA until they were recovered from future overcollections or the end of the rate freeze, whichever came first. Based on the new rules, the $4.5 billion TRA undercollection as of December 31, 2000, and the coal and hydroelectric balancing account overcollections were reclassified, and the TCBA balance was recalculated to be a $2.9 billion undercollection (see further discussion of the CPUC rate increase in the Rate Stabilization Proceeding section and the components of the TCBA undercollection in the Status of Transition and Power Procurement Costs Recovery section of SCE's Regulatory Environment).

On April 9, 2001, Edison International, SCE and the CDWR executed an MOU providing for the sale of SCE's transmission assets, or other assets under certain circumstances, recovery of SCE's net undercollected amount through the application of proceeds of the asset sale and one or more securitization financings, rate-making provisions for recovery of SCE's future power procurement costs, settlement of SCE's legal actions against the CPUC, and other elements of a comprehensive plan (see further discussion in Memorandum of Understanding with the CDWR). The implementation of the MOU requires various regulatory and legislative actions to be taken in the future. Until those actions or actions in other proceedings are taken, which would include modifying or reversing recent CPUC decisions that impair recovery of SCE's power procurement and transition costs, SCE is not able to conclude that, under applicable accounting principles, the $2.9 billion TCBA undercollection (as recalculated above) and $1.3 billion (book value) of other regulatory assets and liabilities, that were to be recovered through the TCBA mechanism by the end of the rate freeze, are probable of recovery through the rate-making process as of December 31, 2000.

As a result, accounting principles generally accepted in the United States require that the net balance of these accounts be written off as a charge to earnings as of December 31, 2000. This write-off consists of the following:

In millions	
TCBA (as recalculated)	**$ 2,878**
Unamortized nuclear investment — net	**610**
Purchased-power settlements	**435**
Unamortized loss on sale of plant	**61**
Other regulatory assets — net	**39**
Subtotal	**4,023**
Flow-through taxes	**218**
Total regulatory assets — net	**4,241**
Less income tax benefit	**(1,720)**
Net write-off	**$ 2,521**

This write-off is included in the income statement as a $4.0 billion charge to provisions for regulatory adjustment clauses, and a $1.5 billion net reduction in income tax expense.

As stated above, an MOU has been negotiated with representatives of the Governor (see Memorandum of Understanding with the CDWR) to resolve the energy crisis. The regulatory and legislative actions set forth in the MOU, if implemented, are expected to result in a rate-making mechanism that would make recovery of these regulatory assets probable. If and when those actions or other actions that make such recovery probable are taken, and the necessary rate-making mechanism is adopted, the regulatory assets would be restored to the balance sheet, with a corresponding increase to earnings.

Excluding the write-off at SCE, Edison International's 2000 basic earnings per share were $1.74, compared with $1.79 in 1999 and $1.86 in 1998. Excluding the write-off, SCE earned $1.42 in 2000, compared with $1.39 in 1999 and $1.37 in 1998. Edison Mission Energy (EME) earned 38¢ in 2000, compared with 37¢ in both 1999 and 1998. Edison Capital earned 41¢ in 2000, compared with 37¢ in 1999 and 29¢ in 1998. Edison Enterprises and Edison International (parent company) incurred losses of 47¢ in 2000, compared with losses of 34¢ in 1999 and 17¢ in 1998. Edison International's 1999 earnings included a special charge of 2¢ (a 6¢ charge at Edison Enterprises, partially offset by a 4¢ gain at SCE).

Unless a rate-making mechanism is implemented in accordance with the MOU described above or other necessary rate-making action is taken, future net undercollections in the TCBA will be charged to earnings as the losses are incurred. The losses (before tax) incurred in this balancing account (as redefined) in January and February 2001 amount to approximately $800 million. SCE anticipates that losses will continue unless a rate-making mechanism is established. In addition to the losses from the TCBA undercollections, Edison International expects its 2001 earnings to be negatively affected by the recent fire and resulting damage at the San Onofre Nuclear Generating Station Unit 3. See further discussion of the San Onofre fire in the San Onofre Nuclear Generating Station section.

2000 vs. 1999

Excluding the $7.58 per share ($2.5 billion after tax) write-off in 2000 and the 4¢ per share gain (discussed in 1999 vs. 1998 below) in 1999, SCE's 2000 earnings were $1.42 compared to $1.35 in 1999. The 7¢ per share increase was mainly due to Edison International's share repurchase program referenced below and discussed in Financial Condition.

EME's 2000 earnings of 38¢ per share increased 1¢ over 1999. The increase in 2000 was mainly due to Edison International's share repurchase program.

Edison Capital's 2000 earnings of 41¢, up 4¢ over 1999, was primarily due to increased earnings from new investments in infrastructure and leveraged leases, partially offset by declining revenue from existing leveraged leases.

Edison Enterprises and the parent company showed a 47¢ loss in 2000, mostly the result of higher interest expense at the parent company.

Excluding the write-off, the reduced number of outstanding shares (due to a repurchase program discussed in Financial Condition) benefited Edison International's earnings per share by 9¢ in 2000.

1999 vs. 1998

SCE's 1999 earnings of $1.39 included a $15 million, or 4¢ per share, tax benefit due to a one-time adjustment that resulted from an Internal Revenue Service ruling. Excluding the gain, SCE's 1999 earnings were $1.35 per share, down 2¢ from 1998. The decrease was mainly due to the accelerated depreciation of SCE's generation assets, partially offset by higher kWh sales in 1999.

EME's 1999 earnings of 37¢ were unchanged from 1998. Higher revenue from existing projects and revenue from projects acquired in 1999 was offset by affiliate stock option accruals. Edison Capital's 1999 earnings were 37¢, up 8¢ from 1998. The increase was mostly due to higher earnings from Edison Capital's infrastructure investments and the sale of interests in affordable housing projects, partially offset by affiliate stock option accruals.

Edison Enterprises and the parent company had a 1999 loss of 34¢ that included a one-time adjustment of 6¢ per share ($23 million after tax) related to actions taken at Edison Enterprises to close five businesses. Excluding the one-time adjustment, Edison Enterprises and the parent company incurred a loss of 28¢ in 1999, compared to a loss of 17¢ in 1998. Increased interest expense at the parent company and continued investment in Edison Enterprises' ongoing businesses contributed to most of the 1999 decrease.

The reduced number of outstanding shares as a result of the share repurchase program benefited Edison International's earnings per share by 6¢ in 1999.

Operating Revenue

SCE's customers are able to choose to purchase power directly from an energy service provider, thus becoming direct access customers, or continue to have SCE purchase power on their behalf. Most direct access customers are billed by SCE, but given a credit for the generation portion of their bills. Under Assembly Bill 1 (First Extraordinary Session) (AB 1X), enacted on February 1, 2001, the CPUC was directed (on a schedule it determines) to suspend the ability of retail customers to select alternative providers of electricity until the CDWR stops buying power for retail customers.

During 2000, as a result of the power shortage in California, SCE's customers on interruptible rate programs (which provide for a lower generation rate with a provision that service can be interrupted if needed, with penalties for noncompliance) were asked to curtail their electricity usage at various times. As a result of noncompliance with SCE's requests, those customers were assessed significant penalties. On January 26, 2001, the CPUC waived the penalties being assessed to noncompliant customers until a reevaluation of the operation of the interruptible programs can be completed.

Electric utility revenue increased in 2000 (as shown in the table below), primarily due to: warmer weather in the second and third quarters of 2000 as compared to the same periods in 1999; increased resale sales; and an increase in revenue related to penalties customers incurred for not adhering to their interruptible contracts. The increase in resale sales resulted from other utilities and municipalities exercising their contractual option to buy more power from SCE as the price of power purchased through the California Power Exchange (PX) and Independent System Operator (ISO) increased significantly in 2000. These increases were partially offset by the credit given to customers who chose direct access. Electric utility revenue increased by less than 1% in 1999, as increased kWh sales and revenue resulting from maintenance work SCE was providing the new owners of generating plants previously sold by SCE was almost completely offset by the credit given to customers who chose direct access. On March 27, 2001, the CPUC affirmed that the interim surcharge of 1¢ per kWh granted on January 4, 2001, is now permanent. See further discussion in Rate Stabilization Proceeding.

In 2000, more than 92% of electric utility revenue was from retail sales. Retail rates are regulated by the CPUC and wholesale rates are regulated by the Federal Energy Regulatory Commission (FERC).

Due to warmer weather during the summer months, electric utility revenue during the third quarter of each year is significantly higher than other quarters.

The changes in electric utility revenue resulted from:

In millions Year Ended December 31,	**2000**	1999	1998
Electric utility revenue —			
Rate changes (including refunds)	**$ 120**	$ (75)	$(498)
Direct access credit	**(434)**	(213)	(29)
Interruptible noncompliance penalty	**102**	6	—
Sales volume changes	**520**	195	(44)
Other	**14**	136	117
Total	**$ 322**	$ 49	$(454)

Nonutility power generation revenue increased in both 2000 and 1999, primarily due to revenue increases related to EME's Illinois, Ferrybridge and Fiddler's Ferry, Homer City and Doga plants.

Due to warmer weather during the summer months, EME's nonutility power generation revenue related to its Homer City plant and the Illinois plants is usually higher during the third quarter of each year. Higher summer pricing for EME's energy projects located on the western coast of the United States, generally causes materially higher third quarter nonutility power generation revenue than other quarters of the year. EME's First Hydro, Ferrybridge and Fiddler's Ferry plants are expected to contribute more to nonutility power generation revenue during the winter months.

Financial services and other revenue increased in 2000, mostly due to customer growth at two of Edison International's subsidiaries (providers of energy management and home security services). Financial services and other revenue increased in 1999, mostly due to the closing of five affordable housing syndications and additional lease transactions at Edison Capital.

Operating Expenses

Fuel expense increased in 2000 when compared to 1999. The increase was primarily due to increased expenses at EME for its Illinois, Ferrybridge and Fiddler's Ferry plants. Fuel expense increased in 1999 compared to 1998, also due to an increase at EME for expenses at Homer City, the Ferrybridge and Fiddler's Ferry plants, the Illinois plants, and the Doga plant in Turkey. This increase was partially offset by a decrease at SCE resulting from the sale of 12 generating plants in 1998.

Prior to April 1998, SCE was required under federal law and CPUC orders to enter into contracts to purchase power from qualifying facilities (QFs) at CPUC-mandated prices even though energy and capacity prices under many of these contracts are generally higher than other sources. Purchased-power expense related to contracts decreased in both 2000 and 1999. The decrease in 2000 was primarily due to a contract adjustment with a state agency, as well as the terms in some of the remaining QF contracts reverting to lower prices. The decrease in 1999 was primarily due to the terms in some of the remaining QF contracts reverting to lower prices, as well as SCE's settlement agreements to terminate certain QF contracts. SCE's settlement agreements with certain QFs decreased purchased-power expense related to contracts by $47 million in 1999. SCE's purchased-power settlement obligations were recorded as a liability. Because the settlement payments were to be recovered through the TCBA mechanism as the payments were made, a regulatory asset was also recorded. As of December 31, 2000, the purchased-power settlement regulatory asset was written off as a charge to earnings. See further discussion of SCE's write-off in Earnings.

In 2000, PX/ISO purchased-power expense increased significantly due to increased demand for electricity in California, dramatic price increases for natural gas (a key input of electricity production), and structural problems within the PX and ISO. The increased volume of higher priced PX purchases was minimally offset by increases in PX sales revenue and ISO net revenue, as well as the use of risk management instruments (gas call options and PX block forward contracts). The gas call options (which were sold in October 2000) and the PX block forward contracts mitigated SCE's transition cost recovery exposure to increases in energy prices. SCE's use of gas call options reduced PX/ISO purchased-power expense by $200 million in 2000 compared to 1999. SCE's use of PX block forward contracts reduced PX/ISO purchased-power expense by $688 million in 2000 compared to 1999. In 1999, PX/ISO purchased-power expense increased compared to 1998, mainly due to three additional months of PX transactions in 1999. However, when 1999 PX purchased-power expense was compared on the same nine-month basis as 1998, the increase was less than 1%, despite the fact that SCE experienced a significant decrease in the volume of kWh sales through the PX. The lower volume of sales through the PX in 1999 was the result of less generation at SCE (due to San Onofre refueling outages in 1999, divestiture of 12 generating plants in 1998 and reduced hydroelectric generation) and fewer purchases from QFs. SCE's use of gas call options decreased PX/ISO purchased-power expense by $8 million in 1999 compared to 1998. SCE's use of PX block forward contracts increased PX/ISO purchased-power expense by $3 million in 1999 compared to 1998. For a further discussion of SCE's hedging instruments and the recent significant increases in power prices, see the SCE Issues section of Market Risk Exposures. As of December 15, 2000, the FERC eliminated the requirement that SCE buy and sell its purchased and generated power through the PX and ISO. See further discussion in Wholesale Electricity Markets.

Due to SCE's noncompliance with the PX's tariff requirement for posting collateral for all transactions in the day-ahead and day-of markets as a result of the downgrade in its credit rating, the PX suspended SCE's market trading privileges for the day-of market effective January 18, 2001, and, for the day-ahead market effective January 19, 2001. See further discussion of SCE's liquidity crisis in Financial Condition.

Provisions for regulatory adjustment clauses increased in 2000 and decreased in 1999. The 2000 increase was mainly due to SCE's write-off as of December 31, 2000, of $4.2 billion in regulatory assets and liabilities as a result of the California energy crisis. See further discussion of SCE's write-off in the Earnings section. In addition, the provision also increased in 2000 due to adjustments to reflect potential regulatory refunds related to the outcome of the CPUC's reevaluation of the operation of the interruptible rate programs. The decrease in 1999 was mainly due to undercollections related to the TCBA and the rate-making treatment of the rate reduction notes. These undercollections were partially offset by overcollections related to the administration of public purpose funds. The rate-making treatment associated with rate reduction notes has allowed for the deferral of the recovery of a portion of the transition-related costs, from a four-year period to a 10-year period. SCE's use of gas call options increased the provisions by $200 million in 2000 compared to 1999, and decreased the provisions by $8 million in 1999 compared to 1998.

Other operation and maintenance expense increased in 2000, primarily reflecting increased plant operating expenses at EME's plants acquired in 1999, and increases at two of Edison International's other nonutility subsidiaries (providers of energy management and home security services). The increases were partially offset by a $26 million decrease at Edison Capital, associated with the syndication of affordable housing investments in 2000; a $60 million decrease at EME in 2000, related to accrued compensation expense reflecting lower valuation of the exchange offer for the affiliate stock option plan; and decreases at SCE in 2000, related to lower expenses for mandated transmission service (known as must-run reliability services); and lower operating expenses at San Onofre. Mandated transmission service expense decreased $120 million in 2000 compared to 1999. The $19 million decrease at San Onofre in 2000 was primarily due to scheduled refueling outages at both units in the first half of 1999. San Onofre had only one refueling outage in 2000. Other operation and maintenance expense increased in 1999, primarily due to: accrued compensation expense incurred at EME and Edison Capital related to affiliate stock options; increased plant operating expenses at EME's plants acquired in 1999, as well as an increase at the Doga project; additional reserves for five affordable housing syndications at Edison Capital; increases at Edison Enterprises' security subsidiary; and the actions taken at Edison Enterprises to close five businesses and refocus the ongoing businesses. In addition, SCE had a net increase in other operation and maintenance expense primarily related to its PX and ISO costs (including grid management costs), partially offset by a decrease resulting from lower expenses incurred for its distribution facilities. Lastly, a nonutility subsidiary incurred a decrease in operating expenses in 1999 related to the sale of real estate in 1998.

Depreciation, decommissioning and amortization expense increased in both 2000 and 1999. The increase in both years is primarily due to EME's 1999 acquisitions of the Illinois, Ferrybridge and Fiddler's Ferry, and Homer City plants.

Net gain on sale of utility plant in 2000 resulted from the sale of additional property related to four of the generating stations SCE sold in 1998. The gains were returned to the ratepayers through the TCBA mechanism.

Other Income and Deductions

Interest and dividend income increased in 2000, primarily due to increases in interest earned on higher balancing account undercollections at SCE and increases at EME related to higher cash balances and foreign exchange gains on intercompany loans denominated in foreign currency. In 1999, interest and dividend income decreased primarily due to lower cash balances at EME.

Other nonoperating income decreased in 2000, primarily due to the gains on sales of equity investments in 1999 at SCE. This decrease was partially offset by the gain on sale of an equity investment at Edison International's insurance subsidiary in 2000. Other nonoperating income increased in 1999, primarily due to the gains on sales of equity investments at SCE and a gain at EME related to the sale of a partial interest in an oil and gas investment.

Interest expense — net of amounts capitalized increased in both 2000 and 1999, reflecting additional long-term subsidiary debt at EME to finance its acquisition of the Homer City, Ferrybridge and Fiddler's Ferry, and Illinois generating plants. Increased long-term debt at the parent company and at Edison Capital also contributed to the increased expense in both 2000 and 1999. Increased expense resulting from higher overall short-term debt balances at both SCE and the parent company, and short-term debt utilized to fund a portion of EME's 1999 acquisitions of the Illinois, the Ferrybridge and Fiddler's Ferry, and the Homer City plants also contributed to the increases in both 2000 and 1999. Interest expense resulting from balancing account overcollections at SCE also contributed to the increase in 2000. Partially offsetting the increase in 1999 was a decrease in SCE's interest on long-term debt due to an adjustment of accrued interest in first quarter 1998 related to the rate reduction notes issued in December 1997.

Other nonoperating deductions decreased in 2000 but increased in 1999. The decrease in 2000 was mainly due to a write-off of start-up costs at EME (in accordance with the implementation of a new accounting rule in first quarter 1999), as well as a decrease at Edison Capital related to syndications of affordable housing projects. The increase in other nonoperating deductions in 1999 compared to 1998 was primarily due to EME's 1999 write-off of start-up costs, partially offset by a decrease at SCE in 1999. The 1999 decrease at SCE resulted from expenses related to a ballot initiative in 1998 more than offsetting additional accruals for regulatory matters in 1999.

Dividends on preferred securities increased in both 2000 and 1999. The increase in 2000 reflects the issuance of quarterly income securities at the parent company in July and October 1999. The 1999 increase in dividends on preferred securities was primarily due to the additional issuance of preferred securities at EME during 1999. Proceeds from the issuances were used primarily to finance EME's 1999 plant acquisitions.

Income Taxes

Income taxes decreased in 2000, primarily due to the $1.5 billion income tax benefit related to SCE's write-off as of December 31, 2000, of regulatory assets and liabilities in the amount of $2.5 billion (after tax). Absent SCE's write-off, Edison International's income tax expense increased in 2000, mainly due to higher pre-tax income, as well as the income tax benefits EME and SCE recorded in 1999. Income taxes decreased in 1999, primarily due to lower pre-tax income, and income tax benefits EME recorded in 1999. In 1999, EME recorded tax benefits associated with a partial sale of its interest in an oil and gas joint venture and the refund of advanced corporation tax payments from the United Kingdom (UK). Also in 1999, SCE recorded a $15 million tax benefit as the result of an Internal Revenue Service ruling.

Financial Condition

Edison International's liquidity is primarily affected by debt maturities, access to capital markets, dividend payments, capital expenditures, investments in partnerships and unconsolidated subsidiaries, and SCE's power purchases. Capital resources include cash from operations and external financings. As a result of SCE's lack of creditworthiness (further discussed in Liquidity Issues), at March 31, 2001, the fair market value of approximately $1.1 billion of Edison International's short-term debt was approximately 80% of its carrying value (as compared to 100% at December 31, 2000) and the fair market value of its long-term debt was approximately 90% of its carrying value (as compared to 92% at December 31, 2000).

Beginning in 1995, Edison International's Board of Directors authorized the repurchase of up to $2.8 billion of its outstanding shares of common stock. Edison International repurchased more than 21 million shares (approximately $400 million) of its common stock during the first six months of 2000. These were the first repurchases since first quarter 1999. Between January 1, 1995, and June 30, 2000, Edison International repurchased $2.8 billion (approximately 122 million shares) of its outstanding shares of common stock funded by dividends from its subsidiaries (primarily from SCE).

Liquidity Issues

SCE

Sustained higher wholesale energy prices that began in May 2000 persisted through Spring 2001. This resulted in an increasing undercollection in the TRA. The increasing undercollection, coupled with SCE's anticipated near-term capital requirements (included in the Projected Capital Requirements section of Financial Condition) and the adverse reaction of the credit markets to continued regulatory uncertainty regarding SCE's ability to recover its current and future power procurement costs, have materially and adversely affected SCE's liquidity. As a result of its liquidity crisis, SCE has taken and is taking steps to conserve cash, so that it can continue to provide service to its customers. As a part of this process, SCE has temporarily suspended payments of certain obligations for principal and interest on outstanding debt and for purchased power. As of March 31, 2001, SCE had $2.7 billion in obligations that were unpaid and overdue including: (1) $626 million to the PX or ISO; (2) $1.1 billion to QFs; (3) $229 million in PX energy credits for energy service providers; (4) $506 million of matured commercial paper; (5) $206 million of principal and interest on its 5⅞% notes; and (6) $7 million of other obligations. SCE's failure to pay when due the principal amount of the 5⅞% series of notes constitutes a default on the series, entitling those noteholders to exercise their remedies. Such failure and the failure to pay commercial paper when due could also constitute an event of default on all the other series of notes (totaling $2.4 billion of outstanding principal) if the trustee or holders of 25% in principal amount of the notes give a notice demanding that the default be cured, and SCE does not cure the default within 30 days. Such failures are also an event of default under SCE's credit facilities, entitling those lenders to exercise their remedies including potential acceleration of the outstanding borrowings of $1.6 billion. If a notice of default is received, SCE could cure the default only by paying $700 million in overdue principal and interest to holders of commercial paper and the 5⅞% notes. Making such payment would further impact SCE's liquidity. If a notice of default were received and not cured, and the trustee or noteholders were to declare an acceleration of the outstanding principal amount of the senior unsecured notes, SCE would not have the cash to pay the obligation and could be forced to declare bankruptcy.

Subject to certain conditions, the bank lenders under SCE's credit facilities agreed to forbear from exercising remedies, including acceleration of borrowed amounts, against SCE with respect to the event of default arising from the failure to pay the 5⅞% notes and commercial paper when due.The initial forbearance agreement expired on February 13, 2001, but it has been extended twice and currently expires on April 28, 2001. At March 31, 2001, SCE had estimated cash reserves of approximately $2.0 billion, which is approximately $700 million less than its outstanding unpaid obligations (discussed above) and overdue amounts of preferred stock dividends (see below). As of March 31, 2001, SCE resumed payment of interest on its debt obligations. If the MOU is implemented, it is expected to allow SCE to recover its undercollected costs and to restore SCE's creditworthiness, which would allow SCE to pay all of its past due obligations.

The parent company has paid and expects to continue to pay its obligations, as they are due, subject to obtaining financing as discussed below. SCE, Edison Capital and the parent company have drawn on their entire lines of credit, and only EME is able to obtain financing of any kind. To isolate EME from the credit downgrades of Edison International and SCE and to help preserve the value of EME, EME has adopted certain amendments to its articles of incorporation and bylaws (see additional discussion in Cash Flows from Financing Activities).

On March 27, 2001, the CPUC ordered SCE and the other California investor-owned utilities to pay QFs for power deliveries on a going forward basis, commencing with April 2001 deliveries. SCE must pay the QFs within 15 days of the end of the QFs' billing period, and QFs are allowed to establish 15-day billing periods. Failure to make a required payment within 15 days of delivery would result in a fine equal to the amount owed to the QF. The CPUC decision also modified the formula used in calculating payments to QFs by substituting natural gas index prices based on deliveries at the Oregon border rather than index prices at the Arizona border. The changes apply to all QFs, where appropriate, whose payments are based on CPUC-approved short-run avoided costs regardless of whether they use natural gas or other resources such as solar or wind.

On March 27, 2001, the CPUC also issued decisions on the California Procurement Adjustment (CPA) calculation (see CDWR Power Purchases discussion) and the approval of a 3¢ per kWh rate increase (see Rate Stabilization Proceeding discussion). Based on these two decisions, SCE estimates that revenue going forward will not be sufficient to recover retained generation, purchased-power and transition costs. In comments filed with the CPUC on March 29, 2001, and April 2, 2001, SCE provided a forecast showing that the net effects of the rate increase, the payment ordered to be made to the CDWR, and the QF decision discussed above could result in a shortfall to the CPA calculation of

$1.7 billion for SCE during 2001. To implement the MOU, it will be necessary for the CPUC to modify or rescind these decisions.

In light of SCE's liquidity crisis, its Board of Directors did not declare quarterly common stock dividends to SCE's parent, Edison International, in either December 2000 or March 2001 and as a result, Edison International's Board of Directors did not declare a common stock dividend to Edison International's shareholders. Also, SCE's Board has not declared the regular quarterly dividends for SCE's cumulative preferred stock, 4.08% Series, 4.24% Series, 4.32% Series, 4.78% Series, 6.05% Series, 6.45% Series and 7.23% Series in 2001. As of March 31, 2001, SCE's preferred stock dividends in arrears were $6 million. As a result of SCE's $2.5 billion charge to earnings as of December 31, 2000, SCE's retained earnings are now in a deficit position and therefore under California law, SCE will be unable to pay dividends as long as a deficit remains. SCE does not meet other tests under which dividends can be paid from sources other than retained earnings. As long as accumulated dividends on SCE's preferred stock remain unpaid, SCE cannot pay any dividends on its common stock.

SCE has begun immediate cost-cutting measures which, together with previously announced actions, such as freezing new hires, postponing certain capital expenditures and ceasing new charitable contributions, are aimed at reducing general operating costs. These actions were expected to impact about 1,450 to 1,850 jobs, affect service levels for customers, and reduce near-term capital expenditures to levels that will not sustain operations in the long term. However, on March 15, 2001, the CPUC issued an order rescinding SCE's layoffs of employees involved with service and reliability. SCE was also ordered to restore specified service levels, make regular reports to the CPUC concerning its cost-cutting measures, and track its cost savings pending future adjustments to rates. The amount of the cost savings affected by the order is not material. SCE's current actions, including the suspension of debt and purchased-power obligations, are intended to allow it to continue to operate while efforts to reach a regulatory solution, involving both state and federal authorities, are underway. Additional actions by SCE may be necessary if the energy and liquidity crisis is not resolved in the near future. See further discussion in Status of Transition and Power Procurement Costs Recovery.

For additional discussion on the impact of California's energy crisis on SCE's liquidity, see Cash Flows from Financing Activities. For a discussion on an agreement to resolve SCE's crisis, see Memorandum of Understanding with the CDWR.

SCE's future liquidity depends, in large part, on whether the MOU is implemented, or other action by the California Legislature and the CPUC is taken in a manner sufficient to resolve the energy crisis and the cash flow deficit created by the current rate structure and the excessively high price of energy. Without a change in circumstances, such as that contemplated by the MOU, resolution of SCE's liquidity crisis and its ability to continue to operate outside of bankruptcy is uncertain.

EME

EME has three corporate credit facilities that are scheduled to expire in May 2001 (total amount of $1 billion) and October 2001 ($500 million). From January 1, 2001, through March 31, 2001, EME has borrowed or issued additional letters of credit of approximately $158 million under these credit facilities and has an unused capacity of approximately $22 million at March 31, 2001. EME plans to refinance its corporate credit facilities through modifications to its existing credit facilities or by entering into new short-term facilities prior to their expiration. EME's cash requirements in 2001 are expected to exceed its cash distributions from its subsidiaries. EME's corporate cash requirements in 2001 include: debt service under its senior notes and intercompany notes resulting from sale-leaseback transactions which total $149 million; capital requirements for projects in development and under construction of $251 million; and development costs, and general and administrative expenses. EME plans to finance these activities through new short-term facilities and through the use of project or subsidiary financings or capital markets debt, depending on market conditions. However, there is no assurance that EME will be able to enter into modifications to its existing credit facilities or obtain additional debt to finance its needs or that the credit facilities can be modified or obtained under similar terms and rates as its agreements. EME does believe that its corporate financing plans will be successful in meeting its cash requirements in 2001. In addition, to reduce debt and provide additional liquidity, EME may sell its interest in individual projects in its project portfolio. Under one of EME's credit facilities, EME is required to use 50% of the net proceeds from the sale of assets and 75% of the net proceeds from the issuance of capital markets debt to repay senior bank indebtedness, in each case in excess of $300 million in the aggregate. There is no assurance that EME will be able to sell assets on favorable terms or that the sale of individual assets will not result in a loss. On April 5, 2001, EME issued $600 million of 9.875% senior notes, due in 2011. EME used the proceeds of the senior notes to repay and permanently reduce portions of its corporate debt consisting of $105 million, $45 million and $75 million of its $700 million, $300 million and $500 million senior credit facilities, respectively. The remaining net proceeds will be used for development costs and general corporate purposes.

The financial performance of the Ferrybridge and Fiddler's Ferry plants has not matched EME's expectations, largely due to lower energy power prices resulting from increased competition, climatic effects and uncertainties surrounding the new electricity trading arrangements discussed in the EME Issues section of Market Risk Exposures. (Also, see additional discussion of the Ferrybridge and Fiddler's Ferry plants in Cash Flows from Financing Activities.) In accordance with asset impairment accounting standards, EME has evaluated the impairment of the Ferrybridge and Fiddler's Ferry power plants and has determined that no impairment exists. As a result of the change in power prices in the UK, EME is considering the sale of the Ferrybridge and Fiddler's Ferry plants. A decision has not been made regarding whether or not the sale of these plants will ultimately occur and, accordingly, these assets are not classified as held for sale. However, if a decision to sell the Ferrybridge and Fiddler's Ferry plants were made, it is likely that the fair value of the assets would be substantially below their book value at December 31, 2000.

Edison Capital

Edison Capital historically received cash from Edison International for the federal and state tax benefits and incentives flowing from Edison Capital's investments that are actually utilized on the Edison International consolidated tax return. However, these tax benefits and incentives are not currently being utilized by Edison International and Edison Capital is not currently receiving cash for them. Without such cash, Edison Capital must meet its current obligations out of existing cash resources and/or by liquidating some of its investments. Any failure by Edison Capital to meet its obligations as and when they become due could be expected to have a material adverse effect on Edison Capital's financial position and ability to conduct future operations. Under the current circumstances, Edison Capital is not pursuing any new investment opportunities.

Edison International

The parent company has fully drawn on the $618 million capacity of its existing 364-day credit facility and has no other short-term borrowing capacity. Because of the payment defaults by SCE on its notes and commercial paper, the parent company is also technically in default under its credit facility due to cross-default provisions. The administrative agent or a majority in interest of the lenders under the credit facility may declare the outstanding loans to be immediately due and payable. The lenders have agreed to forbear from exercising remedies until at least April 28, 2001, subject to certain conditions. The credit facility is scheduled to mature on May 14, 2001. In addition, the parent company has two series of senior unsecured notes that mature on July 18, 2001 ($250 million) and November 1, 2001 ($350 million), respectively. The parent company is in discussions with its bank lenders regarding a possible extension or refinancing of the existing short-term credit facility. In addition, the parent company is seeking to arrange interim financing arrangements that would enable the parent company to pay the $600 million of maturing notes during 2001, and repay the $618 million credit facility at maturity if necessary. The parent company's cash requirements in 2001 are expected to exceed its cash distributions from its subsidiaries. Therefore, the parent company is dependent on obtaining additional financing to meet its cash requirements. The parent company believes that, at a minimum, it will be able to obtain financing through borrowings secured by a pledge of stock of EME. The terms of such borrowings may or may not include a grant of options or warrants to purchase shares of stock of EME in certain circumstances. Alternatively, the parent company may be able to obtain capital market financing if it can obtain an upgrade in its credit ratings. However, there is no assurance that the parent company will be able to obtain the financing that it needs. The parent company does believe that its corporate financing plans will be successful in meeting its cash requirements in 2001. To reduce current cash requirements, the parent company may exercise the right to defer interest payments pursuant to the terms of its outstanding quarterly income debt securities. In addition, to provide additional liquidity, the parent company may sell the stock or assets of certain nonutility subsidiaries. There is no assurance that the parent company will be able to sell assets on favorable terms or that the sale of individual assets will not result in a loss.

Cash Flows from Operating Activities

Net cash provided by operating activities totaled $1.4 billion in 2000, $2.0 billion in 1999 and $1.4 billion in 1998. The decrease in cash flows provided by operating activities in 2000 was primarily due to the extremely high prices SCE paid for energy and ancillary services procured through the PX and ISO. Cash flows provided by operations is expected to increase in the first half of 2001 as SCE conserves cash as result of the liquidity crisis (see Liquidity Issues discussion).

Edison International's cash flow coverage of dividends was 3.8 times for 2000, 5.5 times for 1999 and 3.8 times for 1998. The decrease in 2000 reflects a significant increase in SCE's balancing account undercollections related to the unusually high prices SCE has been paying for energy and ancillary services procured through the PX and ISO. The rate-making treatment of the gains on sales of SCE's generating plants caused the increase in 1999. Beginning in first quarter 2001, the cash flow coverage of dividends calculation will reflect SCE's inability to pay dividends (discussed above in the Liquidity Issues section).

SCE's estimates of cash available for operations in 2001 assume, among other things, satisfactory reimbursement of costs incurred during California's energy crisis, the receipt of adequate and timely rate relief, and the realization of its assumptions regarding cost increases, including the cost of capital.

Cash Flows from Financing Activities

At December 31, 2000, Edison International and its subsidiaries had $400 million of borrowing capacity available under lines of credit totaling $3.6 billion. SCE had total lines of credit of $1.65 billion, with $125 million available for the refinancing of certain variable-rate pollution-control bonds. The parent company had drawn on all of its lines of credit at December 31, 2000. The nonutility subsidiaries had total lines of credit of $1.3 billion, with $274 million available to finance general cash requirements. These unsecured lines of credit have various expiration dates and can be drawn down at negotiated or bank index rates. However, as of January 2, 2001, SCE had drawn on its entire credit lines of $1.65 billion. As of January 31, 2001, Edison Capital had borrowed an additional $130 million on its credit lines. The proceeds were retained as a liquidity reserve. As a result, Edison Capital had no additional credit lines as of January 31, 2001.

The parent company's short-term and long-term debt is used for general corporate purposes, including investments in nonutility business activities. EME uses its short-term and long-term debt to finance acquisitions and development, as well as for general corporate purposes. Edison Capital's short-term and long-term debt is used for general corporate purposes, as well as investments. SCE's short-term debt is used to finance balancing account undercollections, fuel inventories and general cash requirements, including purchased-power payments. Long-term debt is used mainly to finance capital expenditures. External financings are influenced by market conditions and other factors. Because of the $2.5 billion charge to earnings, SCE does not currently meet the interest coverage ratios that are required for SCE to issue additional first mortgage bonds or preferred stock. In addition, because of its current liquidity and credit problems, SCE is unable to obtain financing of any kind.

As a result of investors' concerns regarding the California energy crisis and its impact on SCE's liquidity and overall financial condition, SCE has repurchased $549 million of pollution-control bonds that could not be remarketed in accordance with their terms. These bonds may be remarketed in the future if SCE's credit status improves sufficiently. In addition, the parent company, SCE and Edison Capital have been unable to sell their commercial paper and other short-term financial instruments.

In January 2001, Fitch IBCA, Standard & Poor's and Moody's Investors Service lowered their credit ratings of Edison International, Edison Capital and SCE to substantially below investment grade. In mid-April, Moody's removed the companies' ratings from review for possible downgrade. The ratings remain under review for possible downgrade by the other two agencies.

Subject to the outcome of regulatory, legislative and judicial proceedings, including steps to implement the MOU, SCE intends to pay all of its obligations.

California law prohibits SCE from incurring or guaranteeing debt for its nonutility affiliates. Additionally, the CPUC regulates SCE's capital structure, limiting the dividends it may pay Edison International.

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 non-bypassable residential and small commercial customer rates, which constitute the transition property purchased by SCE Funding LLC. The remaining series of outstanding rate reduction notes have scheduled maturities beginning in 2001 and ending in 2007, with interest rates ranging from 6.17% to 6.42%. The notes are secured by the transition property and are not secured 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, 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. Due to its recent credit rating downgrade, in January 2001, SCE began remitting its customer collections related to the rate reduction notes on a daily basis.

To isolate EME from the credit downgrades of Edison International and SCE and to help preserve the value of EME, EME has adopted certain amendments to its articles of incorporation and bylaws. The provisions include the appointment of an independent EME director whose consent is required for EME to: consolidate or merge with any entity that does not have substantially similar provisions in its organizational documents; institute or consent to bankruptcy, insolvency or similar proceedings or actions; or declare or pay dividends unless certain conditions exist. Such conditions are: EME has an investment grade rating and receives rating agency confirmation that the dividend or distribution will not result in a downgrade, or such dividends do not exceed $32.5 million in any quarter and EME meets a certain interest coverage ratio for the immediately preceding four quarters. EME currently meets this interest coverage ratio.

In July 2000, EME entered into a sale-leaseback transaction for certain equipment, primarily Illinois peaker power units, with a third-party lessor for $300 million. In connection with the sale-leaseback, EME purchased $255 million of notes issued by the lessor that accrue interest at a variable rate depending on EME's credit rating. The notes are due and payable in five years. The gain recognized on the sale of the equipment has been deferred and is being amortized over the term of the lease.

In August 2000, EME entered into a sale-leaseback transaction for power facilities, located in Illinois, with third-party lessors for an aggregate purchase price of $1.4 billion. Under the terms of the leases (between 30 years and 33.75 years), EME will make semi-annual lease payments on each January 2 and July 2, beginning January 2, 2001. The lease costs will be levelized over the terms of the respective leases. The gain recognized on the sale of the power facilities has been deferred and is being amortized over the term of the leases.

In December 2000, EME entered into agreements involving the construction of new projects. Under the terms of one of the agreements, the lessor, as owner of the projects, is responsible for the development and construction costs (approximately $986 million) of the new projects using turbines procured by EME. EME will supervise the development and construction of the projects as the agent of the lessor and upon completion of construction of each project, EME will lease the projects from the lessor. In connection with the lease, EME has provided a residual value guarantee to the lessor at the end of the lease term. EME is required to deposit treasury notes equal to 103% of the construction costs as collateral for the lessor, which can only be used under certain circumstances involving default of EME's performance obligations during construction. The lease agreement provides a purchase option based on the lease balance, which can be exercised at any time during the term. The lease term ends in 2010.

One of the projects using turbines procured by EME may be used to meet the new gas-fired generation commitment resulting from the acquisition of the Illinois plants. As part of the purchase of the generating assets from Commonwealth Edison (ComEd), EME's subsidiary committed to install one or more gas-fired power plants having an additional gross dependable capacity of 500 megawatts (MW) at existing or adjacent power plant sites in Chicago. Commercial operations of this project must be completed by December 15, 2003. The estimated cost to complete the construction of a 500-MW gas-fired power plant is approximately $250 million.

EME has firm commitments related to the Italian wind projects of $3 million to make equity contributions and $17 million for asset purchases. EME also has contingent obligations to make additional contributions of $83 million, primarily for equity support guarantees related to the Paiton project in Indonesia and the ISAB project in Italy.

EME may incur additional obligations to make equity and other contributions to projects in the future. As discussed above, due to its current liquidity crisis, SCE has deferred payments to QFs, among others, due in January, February and March 2001. EME has interests in eight partnerships who own power plants (or QFs) in California and have power purchase agreements with Pacific Gas and Electric Company (PG&E) and/or SCE. Some of the QFs owed by SCE, in which EME has interests, have sought to minimize their exposure by reducing deliveries under power purchase agreements. One of these partnerships has filed a lawsuit against SCE (see further discussion in the Litigation section of SCE's Regulatory Environment). On April 6, 2001, PG&E filed for Chapter 11 bankruptcy protection. As of March 31, 2001, EME's share of accounts receivable due from PG&E was $29 million. It is unclear at this time what additional actions, if any, the partnerships will take in regard to the utilities' suspension of payments. As a result of the deferral of payments to these QFs, the partnerships in which EME has interests, have called on the partners to provide additional capital to fund operating costs of the power plants. Between January 1, 2001, and March 31, 2001, EME subsidiaries have made equity contributions of approximately $115 million to meet capital calls by the partnerships. EME's subsidiaries and the other partners may be required to make additional capital contributions to the partnerships.

EME's UK subsidiary has deferred certain required capital expenditures at the Ferrybridge and Fiddler's Ferry power plants because the plants' financial performance has not met expectations. As a result, the subsidiary is in breach of technical requirements set forth in the plants' financing agreements related to the acquisition of the plants. Also, due to the lower financial performance, the subsidiary's debt service coverage ratio during 2000 declined below the threshold specified in the financing documents. The subsidiary is currently in discussions with financing parties to revise the required capital expenditures program and to waive the breach of the financial ratio covenant for 2000, and related technical defaults. There are no assurances that an agreement can be met. The financing documents state that a breach of the financial ratio covenant constitutes an immediate event of default and, if the event of default is not waived, the financing parties are entitled to enforce their security over the affiliate's assets, including the power plants. Due to the timing of its cash flows and debt service payments, EME's UK subsidiary utilized its debt service reserve to meet its debt service requirements in 2000.

Edison Capital has firm commitments of $228 million to fund affordable housing, and energy and infrastructure investments.

Cash Flows from Investing Activities

Cash flows from investing activities are affected by additions to property and plant, purchases and sales of assets including leasebacks, the nonutility companies' investments in partnerships and unconsolidated subsidiaries, and funding of nuclear decommissioning trusts. Decommissioning costs are recovered in rates. These costs are expected to be funded from independent decommissioning trusts that receive SCE contributions of approximately $25 million per year. In 1995, the CPUC determined the restrictions related to the investments of these trusts. They are: not more than 50% of the fair market value of the qualified trusts may be invested in equity securities; not more than 20% of the fair market value of the trusts may be invested in international equity securities; up to 100% of the fair market values of the trusts may be invested in investment grade fixed-income securities including, but not limited to, government, agency, municipal, corporate, mortgage-backed, asset-backed, nondollar and cash equivalent securities; and derivatives of all descriptions are prohibited. 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 review proceeding will provide input into the contribution analysis for that proceeding's contribution determination.

For 2000, cash flows from investing activities included the proceeds from EME's sale-leaseback transactions with third parties and EME's purchase of notes issued by one of the third-party lessors. For 1999, cash flows from investing activities included EME's 1999 acquisitions of the Homer City, Ferrybridge, Fiddler's Ferry and Illinois generating facilities, as well as an ownership interest in Contact Energy. See further discussion of EME's acquisitions in Note 14 to the Consolidated Financial Statements.

Cash used for the nonutility subsidiaries' investing activities was $1.2 billion in 2000, $9.0 billion in 1999 and $1.2 billion in 1998. The increase in 1999 was primarily due to EME's 1999 acquisitions.

Projected Capital Requirements

Edison International's projected construction expenditures for 2001 are $1.1 billion. This projection reflects SCE's recently announced cost-cutting measures discussed above in the Liquidity Issues section.

Long-term debt maturities and sinking fund requirements for the next five years are: 2001 — $2.3 billion; 2002 — $1.1 billion; 2003 — $1.7 billion; 2004 — $1.8 billion; and 2005 — $499 million.

Estimated noncancelable lease payments for the next five years are: 2001 — $196 million; 2002 — $212 million; 2003 — $210 million; 2004 — $232 million; and 2005 — $269 million.

Preferred stock redemption requirements for the next five years are: 2001 — zero; 2002 — $105 million; 2003 — $9 million; 2004 — $9 million; and 2005 — $9 million.

Market Risk Exposures

Edison International's primary market risk exposures arise from fluctuations in energy prices, oil and gas prices, interest rates and foreign currency exchange rates. Edison International's risk management policy allows the use of derivative financial instruments to manage its financial exposures, but prohibits the use of these instruments for speculative or trading purposes, except at the new trading operation unit acquired by EME in September 2000 (see EME Acquisitions). At December 31, 2000, a 10% change in market rates would have had an immaterial effect on Edison International's financial instruments not specifically addressed below.

SCE Issues

Changes in interest rates and in energy prices can have a significant impact on SCE's results of operations.

SCE is exposed to changes in interest rates primarily as a result of its borrowing and investing activities used for liquidity purposes and to fund business operations, as well as 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. As a result of California's energy crisis, SCE has been exposed to significantly higher interest rates, which has intensified its liquidity crisis (further discussed in the Liquidity Issues section of Financial Condition).

At December 31, 2000, SCE did not believe that its short-term debt was subject to interest rate risk, due to the fair market value being approximately equal to the carrying value. SCE did believe that the fair market value of its fixed-rate long-term debt was subject to interest rate risk. At December 31, 2000, a 10% increase in market interest rates would have resulted in a $222 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 $244 million increase in the fair market value of SCE's long-term debt. See further discussion in Financial Condition of the impact of SCE's lack of creditworthiness on its short-term and long-term debt.

SCE used an interest rate swap to reduce the potential impact of interest rate fluctuations on floating-rate long-term debt. At December 31, 2000, a 10% increase in market interest rates would have resulted in a $5 million increase in the fair value of SCE's interest rate swap. A 10% decrease in market interest rates would have resulted in an $8 million decrease in the fair value of SCE's interest rate swap. As a result of the downgrade in SCE's credit rating below the level allowed under the interest rate hedge agreement, on January 5, 2001, the counterparty on this interest rate swap terminated the agreement. As a result of the termination of the swap, SCE is paying a floating rate on $196 million of its debt due 2008.

Since April 1998, the price SCE paid to acquire power on behalf of customers was allowed to float, in accordance with the 1996 electric utility restructuring law. Until May 2000, retail rates were sufficient to cover the cost of power and other SCE costs. However, since May 2000, market power prices have skyrocketed, creating a substantial gap between costs and retail rates. In response to the dramatically higher prices, the ISO and the FERC have placed certain caps on the price of power, but these caps are set at high levels and are not entirely effective. For example, SCE paid an average of $248 per MW in December 2000, versus an average of $32 per MW in December 1999.

SCE attempted to hedge a portion of its exposure to increases in power prices. However, the CPUC has approved a very limited amount of hedging. In 1997, SCE bought gas call options as a hedge against electricity price increases, since gas is a primary component for much of SCE's power supply. These gas call options were sold in October 2000, resulting in a $190 million gain (lowering purchased-power expense) for 2000. In July 1999, SCE began forward purchases of electricity through the PX block forward market. In November 2000, SCE began purchases of energy through bilateral forward contracts. At December 31, 2000, the nominal value of SCE's block and bilateral forward contracts was $234 million and $798 million, respectively. The block forward contracts reduced purchased-power costs by $684 million in 2000.

At December 31, 2000, a 10% fluctuation in electricity prices would have changed the fair market value of SCE's forward contracts by $187 million.

Because SCE has temporarily suspended payments for purchased power since January 16, 2001, the PX sought to liquidate SCE's remaining block forward contracts. Before the PX could do so, on February 2, 2001, the State of California seized the contracts, but must pay SCE the reasonable value of the contracts under the law. A valuation of the contracts is expected in mid-2001. After other elements of the MOU are implemented, SCE would relinquish all claims against the State for seizing these contracts.

Due to its speculative grade credit ratings, SCE has been unable to purchase additional bilateral forward contracts, and some of the existing contracts were terminated by the counterparties.

In January 2001, the CDWR began purchasing power for delivery to utility customers. On March 27, 2001, the CPUC issued a decision directing SCE to, among other things, immediately pay amounts owed to the CDWR for certain past purchases of power for SCE's customers. See additional discussion of regulatory proceedings related to CDWR activities in the Generation and Power Procurement section of SCE's Regulatory Environment.

EME Issues

Changes in interest rates and in oil and gas prices, electricity pool pricing and fluctuations in foreign currency exchange rates can have a significant impact on EME's results of operations.

EME is exposed to changes in interest rates because it affects the cost of capital needed to finance the construction and operation of EME's projects. EME does not believe that its short-term debt is subject to interest rate risk, due to the fair market value being approximately equal to the carrying value. However, EME's long-term debt with fixed interest rates is subject to interest rate risk. At December 31, 2000, a 10% increase in market interest rates would have resulted in a $96 million decrease in the fair value of EME's long-term debt. A 10% decrease in market interest rates would have resulted in a $104 million increase in the fair value of EME's long-term debt.

EME has mitigated a portion of the risk of interest rate fluctuations by arranging for fixed-rate or variable-rate financing with interest rate swaps or other hedging mechanisms for a number of its project financings. Several of EME's interest rate swap agreements mature prior to their underlying debt. At December 31, 2000, a 10% fluctuation in market interest rates would have changed the fair value of EME's interest rate hedge agreements by $17 million.

EME hedges a portion of the electric output of its plants in order to lock in desirable outcomes. EME also manages the margin between electric prices and fuel prices when deemed appropriate. EME uses forward contracts, swaps, futures or option contracts to achieve these objectives.

Electric power generated at the Homer City plant is sold under bilateral arrangements with domestic utilities and power marketers under short-term contracts (two years or less) or to the Pennsylvania-

New Jersey-Maryland Power Pool (PJM) or the New York Independent System Operator (NYISO). These pools have short-term markets, which establish an hourly clearing price. The Homer City plant is located in the PJM control area and is physically connected to high-voltage transmission lines serving both the PJM and NYISO markets. The Homer City plant can also transmit power to the midwestern United States.

Electric power generated at the Illinois plants is sold under power purchase agreements in which ComEd will purchase capacity and have the right to purchase energy generated by EME's Illinois plants. The agreements, which began in December 1999 and have a term of up to five years, provide for capacity and energy payments. In January 2001, ComEd assigned its rights to Exelon Generation Company LLC (ExGen). ExGen will be obligated to make a capacity payment for the units under contract and an energy payment for the electricity produced by these units and taken by ExGen. The capacity payments provide the Illinois plants revenue for fixed charges, and the energy payments compensate the Illinois plants for variable costs of production. If ExGen does not order all the power from the units under contract, the Illinois plants may sell, subject to specified conditions, the excess energy at market prices to neighboring utilities, municipalities, third-party electric retailers, large consumers and power marketers on a spot basis.

In September 2000, EME acquired the trading operations of Citizens Power LLC. As a result of this acquisition, EME has expanded its trading operations beyond the traditional marketing of electric power. EME's trading and price risk management activities give rise to market risk, which represents the potential loss that can be caused by a change in the market value of a particular commitment. Market risks are actively monitored to ensure compliance with the risk management policies of EME, which limit its total net exposure. EME performs a value at risk analysis daily to monitor its overall market risk exposure. Value at risk measures the worst expected loss over a given time interval, under normal market conditions, at a given confidence level. Given the inherent limitations of value at risk and relying on a single risk measurement tool, EME supplements this approach with other techniques, including the use of stress testing and worst-case scenario analysis, as well as stop limits and counterparty credit exposure limits.

At December 31, 2000, a 10% fluctuation in fuel oil, natural gas and electricity forward prices would have changed the fair market value of energy contracts utilized by EME's domestic trading unit in energy trading and price risk management activities by $16 million.

EME's projects in the UK currently sell their electric energy and capacity through a centralized electricity pool, which establishes a half-hourly clearing price, or pool price, for electric energy. This system had been in place since 1989 but was replaced on March 27, 2001, with a bilateral physical trading system, referred to as the new electricity trading arrangements.

The new electricity trading arrangements are the direct result of an October 1997 request by the Minister for Science, Energy and Industry who asked the UK Director General of Electricity Supply to review the operation of the pool pricing system. In July 1998 the Director General proposed that the current structure of contracts for differences and compulsory trading via the pool at half-hourly clearing prices bid a day ahead be abolished. The UK Government accepted the proposals in October 1998 subject to reservations. Following this, further proposals were published by the Government and the Director General in July and October 1999. The proposals include, among other things, the establishment of a spot market or voluntary short-term power exchanges operating from 24 hours to three hours before a trading period; a balancing mechanism to enable the system operator to balance generation and demand and resolve any transmission constraints; a mandatory settlement process for recovering imbalances between contracted and metered volumes with strong incentives for being in balance; and a Balancing and Settlement Code Panel to oversee governance of the balancing mechanism. Contracting over time periods longer than the day-ahead market is not directly affected by the proposals. Physical bilateral contracts will replace the current contracts for differences, but will function in a similar manner. However, it remains difficult to evaluate the future impact of the proposals.

A key feature of the new electricity trading arrangements is to require firm physical delivery, which means that a generator must deliver, and a consumer must take delivery, against their contracted positions or face assessment of energy imbalance penalty charges by the system operator. A consequence of this should be to increase greatly the motivation of parties to contract in advance and develop forwards and futures markets of greater liquidity than at present. Recent experience has been that the new electricity trading arrangements have placed a significant downward pressure on forward contract prices. Furthermore, another consequence may be that counterparties may require additional credit support, including parent company guarantees or letters of credit. Legislation in the form of the Utilities Act, which was approved in July 2000, allows for the implementation of new electricity trading arrangements and the necessary amendments to generators' licenses. Various key documents were designated by the Secretary of State and signed by participants in August 2000; however, due to difficulties encountered during testing, implementation of the new trading arrangements was delayed from November 2000 until March 27, 2001.

The Utilities Act sets a principal objective for the UK Government and the Director General to ''protect the interests of consumers . . . where appropriate by promoting competition . . .'' This represents a shift in emphasis toward consumer interest. But this is qualified by the recognition that license holders should be able to finance their activities. The Act also contains new powers for the Government to issue guidance to the Director General on social and environmental matters, changes to the procedures for modifying licenses, and a new power for the Director General to impose financial penalties on companies for breach of license conditions. EME will be monitoring the operation of these new provisions.

The Loy Yang B project in Australia sells its electrical energy through a centralized electricity pool, which provides for a system of generator bidding, central dispatch and a settlements system based on a clearing market for each half-hour of every day. The National Electricity Market Management Company, operator and administrator of the pool, determines a system marginal price each half-hour. To mitigate the exposure to price volatility of the electricity traded in the pool, Loy Yang B has entered into a number of financial hedges. From May 8, 1997, to December 31, 2000, 53% to 64% of the plant output sold was hedged under vesting contracts, with the remainder of the plant capacity hedged under the State hedge described below. Vesting contracts were put into place by the State Government of Victoria, Australia, between each generator and each distributor, prior to the privatization of electric power distributors in order to provide more predictable pricing for those electricity customers that were unable to choose their electricity retailer. Vesting contracts set base strike prices at which the electricity will be traded, and the parties to the agreement make payments, calculated based on the difference between the price in the contract and the half-hourly pool clearing price for the element of power under contract. Vesting contracts were sold in various structures and accounted for as electricity rate swap agreements. The State hedge with the State Electricity Commission of Victoria is a long-term contractual arrangement based upon a fixed price commencing May 8, 1997, and terminating October 31, 2016. The State government guarantees the State Electricity Commission of Victoria's obligations under the State hedge. From January 2001 to July 2014, approximately 77% of the plant output sold is hedged under the State hedge. From August 2014 to October 2016, approximately 56% of the plant output sold is hedged under the State hedge. Additionally, Loy Yang B entered into a number of fixed forward electricity contracts effective January 2001, which expire in either January 2002 or January 2003, and which will further mitigate against the price volatility of the electricity pool.

The New Zealand government has been undergoing a steady process of electric industry deregulation since 1987. Reform in the distribution and retail supply sector began in 1992 with legislation that deregulated electricity distribution and provided for competition in the retail electric supply function. The New Zealand Energy Market, established in 1996, is a voluntary competitive wholesale market that allows for the trading of physical electricity on a half-hourly basis. The Electricity Industry Reform Act, which was passed in July 1998, was designed to increase competition at the wholesale generation level by splitting up Electricity Company of New Zealand Limited, the large state-owned generator, into three separate generation companies. The Electricity Industry Reform Act also prohibits the ownership of both generation and distribution assets by the same entity.

The New Zealand government commissioned an inquiry into the electricity industry in February 2000. This Inquiry Board's report was presented to the government in mid-2000. The main focus of the report was on the monopoly segments of the industry, transmission and distribution, with substantial limitations being recommended in the way in which these segments price their services in order to limit their monopoly power. Recommendations were also made with respect to the retail customer in order to reduce barriers to customers switching. In addition, the Board made recommendations in relation to the wholesale market's governance arrangements with the purpose of streamlining them. The recommended changes are now being progressively implemented.

At December 31, 2000, a 10% increase in pool prices would have resulted in a $131 million decrease in the fair value of electricity rate swap agreements. A 10% decrease in pool prices would have resulted in a $130 million increase in the fair value of electricity rate swap agreements.

At December 31, 2000, a 10% fluctuation in electricity prices would have changed the fair value of forward contracts entered into by EME's Loy Yang B project by $2 million.

Foreign currencies in the UK, Australia and New Zealand decreased in value compared to the US dollar. The decrease in value of these currencies was the primary reason for EME's foreign currency translation loss in 2000, included in Edison International's Consolidated Statements of Changes in Common Shareholders' Equity. At December 31, 2000, a 10% fluctuation in the value of foreign currencies would have resulted in a foreign currency translation change of $197 million.

In December 2000, EME entered into foreign currency forward exchange contracts, in the ordinary course of business, to protect itself from adverse currency rate fluctuations on anticipated foreign currency commitments with varying maturities ranging from January 2001 to July 2002. The periods of the foreign currency forward exchange contracts correspond to the periods of the hedged transactions. At December 31, 2000, the outstanding notional amount of the contracts was $91 million, consisting of contracts to exchange US dollars to pound sterling.

At December 31, 2000, a 10% fluctuation in exchange rates would have changed the fair value of EME's foreign currency exchange contracts by approximately $6 million.

Fluctuations in foreign currency exchange rates can affect the amount of EME's equity contributions to, and distributions from its international projects. As EME continues to expand into foreign markets, fluctuations in foreign currency exchange rates can be expected to have a greater impact on EME's results of operations in the future. At times, EME has hedged a portion of its current exposure to fluctuations in foreign exchange rates through financial derivatives, offsetting obligations denominated in foreign currencies, and indexing underlying project agreements to US dollars or other indices reasonably expected to correlate with foreign exchange movements. Statistical forecasting techniques are used to help assess foreign exchange risk and the probabilities of various outcomes. There can be no assurance, however, that fluctuations in exchange rates will be fully offset by hedges or that currency movements and the relationship between macro-economic variables will behave in a manner that is consistent with historical or forecasted relationships.

Edison Capital Issues

Changes in interest rates and fluctuations in foreign currency exchange rates can have a significant impact on Edison Capital's results of operations.

Edison Capital is exposed to changes in interest rates primarily as a result of its borrowing and investing activities used for general corporate purposes, as well as investments. The nature and amount of Edison Capital's long-term and short-term debt can be expected to vary as a result of future business requirements, market conditions and other factors.

At December 31, 2000, Edison Capital did not believe that its short-term debt was subject to interest rate risk, due to the fair market value being approximately equal to the carrying value. Edison Capital did believe that the fair market value of its fixed-rate long-term debt was subject to interest rate risk. At December 31, 2000, a 10% increase in market interest rates would have resulted in an $11 million decrease in the fair market value of Edison Capital's long-term debt. A 10% decrease in market interest rates would have resulted in a $12 million increase in the fair market value of Edison Capital's long-term debt.

Edison Capital has entered into interest rate swap agreements to reduce actual or expected exposure to interest rate fluctuations. At December 31, 2000, a 10% fluctuation in market interest rates would have changed the fair value of Edison Capital's swap agreements by approximately $5 million.

Edison Capital has entered into foreign currency contracts to reduce the potential impact of changes in foreign exchange rates and future foreign currency denominated cash flows. At December 31, 2000, the outstanding notional amount of the contracts was approximately $13 million, consisting of contracts to exchange US dollars to Great British Pounds.

At December 31, 2000, a 10% increase in exchange rates would have resulted in an immaterial decrease in the fair value of Edison Capital's foreign currency contracts. A 10% decrease in exchange rates would have resulted in a $2 million decrease in the fair value of Edison Capital's foreign currency contracts.

Edison International Issues

The parent company is exposed to changes in interest rates primarily as a result of its borrowing and investing activities used for general corporate purposes, including investments in nonutility business activities. The nature and amount of the parent company's long-term and short-term debt can be expected to vary as a result of future business requirements, market conditions and other factors.

At December 31, 2000, the parent company did not believe that its short-term debt was subject to interest rate risk, due to the fair market value being approximately equal to the carrying value. The parent company did believe that the fair market value of its fixed-rate long-term debt was subject to interest rate risk. At December 31, 2000, a 10% increase in market interest rates would have resulted in a $23 million decrease in the fair market value of the parent company's long-term debt. A 10% decrease in market interest rates would have resulted in a $24 million increase in the fair market value of the parent company's long-term debt.

At March 31, 2001, due to the liquidity issues it faces, the parent company now believes that its short-term debt is subject to interest rate risk. A 10% increase in market interest rates would have resulted in a $9 million decrease in the fair market value of the parent company's short-term debt. A 10% decrease in market interest rates would have resulted in a $10 million increase in the fair market value of the parent company's short-term debt.

Paiton Project

A wholly owned subsidiary of EME owns a 40% interest and has a $490 million investment (at December 31, 2000) in the Paiton project, a 1,230-MW coal-fired power plant in Indonesia. The revenue schedule is higher in the early years and decreases over time. The plant's output is fully contracted with the state-owned electricity company for payment in Indonesian Rupiah, with the portion of such payments intended to cover non-Rupiah project costs (including returns to investors) adjusted to account for exchange rate fluctuations between the Indonesian Rupiah and the US dollar. The project received substantial finance and insurance support from the Export-Import Bank of the United States and various other governmental agencies. The state-owned electricity company's payment obligations are supported by the Indonesian government.

The projected rate of growth of the Indonesian economy and the exchange rate of Indonesian Rupiah into US dollars have deteriorated significantly since the Paiton project was contracted, approved and financed. The Paiton project's senior debt ratings have been reduced from investment grade to speculative grade based on the rating agencies' determination that there is increased risk that the state-owned electricity company might not be able to honor the power purchase agreement with Paiton. The Indonesian government has arranged to reschedule senior debt owed to foreign governments and has entered into discussions about rescheduling senior debt owed to private lenders.

One of the Paiton units began commercial operation in May 1999 and the other unit in July 1999. Because of the economic downturn, the state-owned electricity company was experiencing low electricity demand and, therefore ordered no power from the Paiton plant through February 2000. The state-owned electricity company filed a lawsuit contesting the validity of its agreement to purchase electricity from the Paiton project. The lawsuit was withdrawn in January 2000, and in connection with this withdrawal, the parties entered into an interim agreement for the period through December 31, 2000, under which the levels of power ordered, and the fixed and energy payment amounts were agreed. As of December 31, 2000, the state-owned electricity company had made all fixed payments due under the interim agreement totaling $115 million and all payments due for energy delivered by the plant to the state-owned electricity company. As part of the continuing negotiations on a long-term restructuring of the revenue schedule, Paiton and the state-owned electricity company agreed in January 2001 on a Phase I agreement for the period from January 1, 2001, through June 30, 2001. This agreement provides for fixed monthly payments of $108 million over its six-month duration and for the payment for energy delivered to the state-owned electricity company from the plant during this period. Paiton and the state-owned electricity company intend to complete the negotiations of the future phases of a new long-term revenue schedule during the six-month duration of the Phase I agreement. To date, the state-owned electricity company has made all fixed and energy payments due under the Phase I agreement.

In October 1999, the project entered into an interim agreement with its lenders in which the lenders waived defaults during the term of the agreement and effectively agreed to defer payments of principal until July 31, 2000. The lenders had agreed to an extension of the agreement through December 31, 2000 (which has now been extended through December 31, 2001). Paiton has received lender approval of the Phase I agreement.

Under the terms of the power purchase agreement, the state-owned electricity company has been required to continue to pay for capacity and fixed operating costs once each unit and the plant achieved commercial operation. As of December 31, 2000, the state-owned electricity company had not paid invoices totaling $814 million for capacity charges and fixed operating costs under the power purchase agreement. All overdue amounts under the power purchase agreement continue to accumulate, minus the fixed monthly payments made under the year 2000 interim agreement and under the recently agreed Phase I agreement, with the payment of these overdue amounts to be dealt with in connection with the overall long-term restructuring of the revenue schedule. In this regard, under the Phase I agreement, Paiton has agreed that, so long as the Phase I agreement is complied with, it will seek to recoup no more than $590 million of the above overdue amounts, the payment of which is to be dealt with in connection with the overall revenue schedule restructuring.

Any material modifications of the power purchase agreement resulting from the continuing negotiation of a new long-term revenue schedule could require a renegotiation of the Paiton project's debt agreements. The impact of any such renegotiations with the state-owned electricity company, the Indonesian government or the project's creditors on EME's expected return on its investment in Paiton is uncertain at this time; however, EME believes that it will ultimately recover its investment in the project.

EME Acquisitions

In March 2000, EME completed its acquisition of Edison Mission Wind Power Italy B.V., formerly known as Italian Vento Power Corp. Energy 5 B.V. Edison Mission Wind owns a 50% interest in a series of wind-generated power projects in operation or under development in Italy. When all of the projects under development are completed, currently scheduled for 2002, the total capacity of these projects will be 283 MW. The purchase price of the acquisition is $44 million with equity contribution obligations of up to $16 million, depending on the number of projects that are ultimately developed. As of December 31, 2000, EME has paid $27 million toward the purchase price and $13 million in equity contributions.

In September 2000, EME completed a transaction with P&L Coal Holdings Corporation and Gold Fields Mining Corporation to acquire the trading operations of Citizens Power LLC and a minority interest in certain structured transaction investments relating to long-term power purchase agreements. The purchase price of $45 million was based on $25 million plus the fair market value of the trading portfolio and the structured transaction investments at the date of acquisition. The acquisition was funded with cash. As a result of this acquisition, EME has expanded its trading operations beyond the traditional marketing of its electric power. By the end of the third quarter of 2000, the Citizens' trading operations were merged into EME's marketing operations.

In November 2000, EME completed a transaction with Texaco Inc. to purchase a proposed 560-MW gas-fired combined cycle project (Sunrise project) in central California. The acquisition includes all rights, title and interest held by Texaco in the Sunrise project, except that Texaco has an option to repurchase a 50% interest in the project prior to commercial operation. As part of this transaction, EME also acquired an option to purchase two gas turbines that it plans to utilize in the project, and provided Texaco options to purchase two of the turbines under a lease agreement and to acquire 50% interests in 1,000 MW of future power plant projects EME designates. Phase I is scheduled for completion in August 2001 and Phase II is scheduled for completion in June 2003. The total purchase price was $27 million. The acquisition was funded with cash. The estimated construction costs are approximately $400 million. As discussed in the California Governor's Proposal section of SCE's Regulatory Environment, one of the elements of the Governor's proposal is the commitment of the entire output of the Sunrise project being developed by EME, at cost-based rates for 10 years. As a result, EME is negotiating with the CDWR regarding detailed terms and conditions of a long-term, cost-based power purchase agreement. No assurance can be provided that EME will be successful in reaching a final agreement.

In February 2001, EME completed the acquisition of a 50% interest in CBK Power Co. Ltd. in exchange for $20 million. CBK Power has entered into a 25-year build-rehabilitate-transfer-and-operate agreement with National Power Corporation related to the 726-MW Caliraya-Botocan-Kalayaan (CBK) hydroelectric project located in the Philippines. Financing for this $460 million project has been completed with equity contributions of $117 million (EME's share is $59 million) required to be made upon completion of the rehabilitation and expansion, currently scheduled in 2003. Debt financing has been arranged for the remainder of the cost for this project.

SCE's Regulatory Environment

SCE operates in a highly regulated environment in which it has an obligation to deliver electric service to customers in return for an exclusive franchise within its service territory and certain obligations of the regulatory authorities to provide just and reasonable rates. In 1996, state lawmakers and the CPUC initiated the electric industry restructuring process. SCE was directed by the CPUC to divest the bulk of its gas-fired generation portfolio. Today, independent power companies own those generating plants. Along with electric industry restructuring, a multi-year freeze on the rates that SCE could charge its customers was mandated and transition cost recovery mechanisms (as described in Status of Transition and Power Procurement Costs Recovery) allowing SCE to recover its stranded costs associated with generation-related assets were implemented. California's electric industry restructuring statute included provisions to finance a portion of the stranded costs that residential and small commercial customers would have paid between 1998 and 2001, which allowed SCE to reduce rates by at least 10% to these customers, effective January 1, 1998. These frozen rates were to remain in effect until the earlier of March 31, 2002, or the date when the CPUC-authorized costs for utility-owned generation assets and obligations were recovered. However, since May 2000, the prices charged by sellers of power have escalated far beyond what SCE can currently charge its customers. See further discussion in Wholesale Electricity Markets.

Generation and Power Procurement

During the rate freeze, revenue from generation-related operations has been determined through the market and transition cost recovery mechanisms, which included the nuclear rate-making agreements. The portion of revenue related to coal generation plant costs (Mohave Generating Station and Four Corners Generating Station) that was made uneconomic by electric industry restructuring has been recovered through the transition cost recovery mechanisms. After April 1, 1998, coal generation operating costs have been recovered through the market. The excess of power sales revenue from the coal generating plants over the plants' operating costs has been accumulated in a coal generation balancing account. SCE's costs associated with its hydroelectric plants have been recovered through a performance-based mechanism. The mechanism set the hydroelectric revenue requirement and established a formula for extending it through the duration of the electric industry restructuring transition period, or until market valuation of the hydroelectric facilities, whichever occurred first. The mechanism provided that power sales revenue from hydroelectric facilities in excess of the hydroelectric revenue requirement is accumulated in a hydroelectric balancing account. In accordance with a CPUC decision issued in 1997, the credit balances in the coal and hydroelectric balancing accounts were transferred to the TCBA at the end of 1998 and 1999. However, due to the CPUC's March 27, 2001, rate stabilization decision, the credit balances in these balancing accounts have now been transferred to the TRA on a monthly basis, retroactive to January 1, 1998. In addition, the TRA balance, whether over- or undercollected, has now been transferred to the TCBA on a monthly basis, retroactive to January 1, 1998. Due to a December 15, 2000, FERC order, SCE is no longer required to buy and sell power exclusively through the ISO and PX. In mid-January 2001, the PX suspended SCE's trading privileges for failure to post collateral due to SCE's rating agency downgrades. As a result, power from SCE's coal and hydroelectric plants is no longer being sold through the market and these two balancing accounts have become inactive. As a key element of the MOU, SCE would continue to own its generation assets, which would be subject to cost-based ratemaking, through 2010. The MOU calls for the CPUC to adopt cost recovery mechanisms consistent with SCE obtaining and maintaining an investment grade credit rating.

SCE has been recovering its investment in its nuclear facilities on an accelerated basis in exchange for a lower authorized rate of return on investment. SCE's nuclear assets are earning an annual rate of return on investment of 7.35%. In addition, the San Onofre incentive pricing plan authorizes a fixed rate of approximately 4¢ per kWh generated for operating costs including incremental capital costs, nuclear fuel and nuclear fuel financing costs. The San Onofre plan commenced in April 1996, and ends at the earlier of December 2001 or the date when the statutory rate freeze ends for the accelerated recovery portion, and in December 2003 for the incentive-pricing portion. The Palo Verde Nuclear Generating Station's operating costs, including incremental capital costs, and nuclear fuel and nuclear fuel financing costs, are subject to balancing account treatment. The Palo Verde plan commenced in January 1997 and ends in December 2001. The benefits of operation of the San Onofre units and the Palo Verde units are required to be shared equally with ratepayers beginning in 2004 and 2002, respectively. Beginning January 1, 1998, both the San Onofre and Palo Verde rate-making plans became part of the TCBA mechanism. These rate-making plans and the TCBA mechanism will continue for rate-making purposes at least through the end of the rate freeze period. Under the MOU, both nuclear facilities would be subject to cost-based ratemaking upon completion of their respective rate-making plans and the sharing mechanisms that were to begin in 2004 and 2002 would be eliminated. However, due to the various unresolved regulatory and legislative issues (as discussed in Status of Transition and Power Procurement Costs Recovery), SCE is no longer able to conclude that the unamortized nuclear investment regulatory assets (as discussed in Accounting for Generation-Related Assets and Power Procurement Costs) are probable of recovery through the rate-making process. As a result, these balances were written off as a charge to earnings as of December 31, 2000 (see further discussion in Earnings).

In 1999, SCE filed an application with the CPUC establishing a market value for its hydroelectric generation-related assets at approximately $1.0 billion (almost twice the assets' book value) and proposing to retain and operate the hydroelectric assets under a performance-based, revenue-sharing mechanism. If approved by the CPUC, SCE would be allowed to recover an authorized, inflation-indexed operations and maintenance allowance, as well as a reasonable return on capital investment. A revenue-sharing arrangement would be activated if revenue from the sale of hydroelectricity exceeds or falls short of the authorized revenue requirement. SCE would then refund 90% of the excess revenue to ratepayers or recover 90% of any shortfalls from ratepayers. If the MOU is implemented, SCE's hydroelectric assets will be retained through 2010 under cost-based rates, or they may be sold to the state if a sale of SCE's transmission assets is not completed under certain circumstances. In June 2000, SCE credited the TCBA with the estimated excess of market value over book value of its hydroelectric generation assets and simultaneously recorded the same amount in the generation asset balancing account (GABA), pursuant to a CPUC decision. This balance was to remain in GABA until final market valuation of the hydroelectric assets. If there were a difference in the final market value, it would have been credited to or recovered from customers through the TCBA. Due to the various unresolved regulatory and legislative issues (as discussed in Status of Transition and Power Procurement Costs Recovery), the GABA transaction was reclassified back to the TCBA, and as discussed in the Earnings section, the TCBA balance (as recalculated based on a March 27, 2001, CPUC interim decision discussed in Rate Stabilization Proceeding) was written off as of December 31, 2000.

During 2000, SCE entered into agreements to sell the Mohave, Palo Verde and Four Corners generation stations. The sales were pending various regulatory approvals. Due to the shortage of electricity in California and the increasing wholesale costs, state legislation was enacted in January 2001 barring the sale of utility generation stations until 2006. Under the MOU, SCE would continue to retain its generation assets through 2010.

CDWR Power Purchases

Pursuant to an emergency order signed by the Governor, the CDWR began making emergency power purchases for SCE's customers on January 18, 2001. On February 1, 2001, AB 1X was enacted into law. The new law authorized the CDWR to enter into contracts to purchase electric power and sell power at cost directly to retail customers being served by SCE, and authorized the CDWR to issue revenue bonds to finance electricity purchases. The new law directed the CPUC to determine the amount of a CPA as a residual amount of SCE's generation-related revenue, after deducting the cost of SCE-owned generation, QF contracts, existing bilateral contracts and ancillary services. The new law also directed the CPUC to determine the amount of the CPA that is allocable to the power sold by the CDWR which will be payable to the CDWR when received by SCE. On March 7, 2001, the CPUC issued an interim order in which it held that the CDWR's purchases are not subject to prudency review by the CPUC, and that the CPUC must approve and impose, either as a part of existing rates or as additional rates, rates sufficient to enable the CDWR to recover its revenue requirements.

On March 27, 2001, the CPUC issued an interim CDWR-related order requiring SCE to pay the CDWR a per kWh price equal to the applicable generation-related retail rate per kWh for electricity (based on rates in effect on January 5, 2001), for each kWh the CDWR sells to SCE's customers. The CPUC determined that the generation-related retail rate should be equal to the total bundled electric rate (including the 1¢ per kWh temporary surcharge adopted by the CPUC on January 4, 2001) less certain nongeneration related rates or charges. For the period January 19 through January 31, 2001, the CPUC ordered SCE to pay the CDWR at a rate of 6.277¢ per kWh. The CPUC determined that the company-wide generation-related rate component is 7.277¢ per kWh (which will increase to 10.277¢ per kWh for electricity delivered after March 27, 2001, due to the 3¢ surcharge discussed in Rate Stabilization Proceeding), for each kWh delivered to customers beginning February 1, 2001, until more specific rates are calculated. The CPUC ordered SCE to pay the CDWR within 45 days after the CDWR supplies power to retail customers. Using these rates, SCE has billed customers $196 million for energy sales made by the CDWR during the period January 19 through March 31, 2001, and has forwarded $52 million to the CDWR on behalf of these customers as of March 31, 2001.

On April 3, 2001, the CPUC adopted the method (originally proposed in the March 27 CDWR-related order discussed above) it will use to calculate the CPA (which was established by AB 1X) and then applied the method to calculate a company-wide CPA rate for SCE. The CPUC used that rate to determine the CPA revenue amount that can be used by the CDWR for issuing bonds. The CPUC stated that its decision is narrowly focused to calculate the maximum amount of bonds that the CDWR may issue and does not dedicate any particular revenue stream to the CDWR. The CPUC determined that SCE's CPA rate is 1.120¢ per kWh, which generates annual revenue of $856 million. In its calculation of the CPA, the CPUC disregarded all of the adjustments requested by SCE in its comments filed on March 29 and April 2, 2001. SCE's comments included, among other things, a forecast showing that the net effect of the rate increases (discussed in Rate Stabilization Proceeding), as well as the March 27 QF payment decision (discussed in Liquidity Issues) and the payments ordered to be made to CDWR (discussed above), could result in a shortfall in the CPA calculation of $1.7 billion for SCE during 2001. SCE estimates that its future revenue will not be sufficient to cover its retained generation, purchased-power and transition costs. To implement the MOU described in Memorandum of Understanding with the CDWR, the CPUC will need to modify the calculation methods and provide reasonable assurance that SCE will be able to recover its ongoing costs.

SCE believes that the intent of AB 1X was for the CDWR to assume full responsibility for purchasing all power needed to serve the retail customers of electric utilities, in excess of the output of generating plants owned by the electric utilities and power delivered to the utilities under existing contracts. However, the CDWR has stated that it is only purchasing power that it considers to be reasonably priced, leaving the ISO to purchase in the short-term market the additional power necessary to meet system requirements. The ISO, in turn, takes the position that it will charge SCE for the costs of power it purchases in this manner. If SCE is found responsible for any portion of the ISO's purchases of power for resale to SCE's customers, SCE will continue to incur purchased-power costs in addition to the unpaid costs described above. In its March 27, 2001, interim order, the CPUC stated that it cannot assume that the CDWR will pay for the ISO purchases and that it does not have the authority to order the CDWR to do so. Litigation among certain power generators, the ISO and the CDWR (to which SCE is not a party), and proceedings before the FERC (to which SCE is a party), may result in rulings clarifying the CDWR's financial responsibility for purchases of power. On April 6, 2001, the FERC issued an order confirming that the ISO must have a creditworthy buyer for any transactions. In any event, SCE takes the position that it is not responsible for purchases of power by the CDWR or the ISO on or after January 18, 2001, the day after the Governor signed the order authorizing the CDWR to begin purchasing power for utility customers. SCE cannot predict the outcome of any of these proceedings or issues. The recently executed MOU states that the CDWR will assume the entire responsibility for procuring the electricity needs of retail customers within SCE's service territory through December 31, 2002, to the extent those needs are not met by generation sources owned by or under contract to SCE (SCE's net short position). SCE will resume buying power for its net short position after 2002. The MOU calls for the CPUC to adopt cost recovery mechanisms to make it financially practicable for SCE to reassume this responsibility.

Status of Transition and Power Procurement Costs Recovery

SCE's transition costs include power purchases from QF contracts (which are the direct result of prior legislative and regulatory mandates), recovery of certain generating assets and regulatory commitments consisting of recovery of costs incurred to provide service to customers. Such commitments include the recovery of income tax benefits previously flowed through to customers, postretirement benefit transition costs, accelerated recovery of investment in San Onofre Units 2 and 3 and the Palo Verde units, and certain other costs. Transition costs related to power-purchase contracts are being recovered through the terms of each contract. Most of the remaining transition costs may be recovered through the end of the transition period (not later than March 31, 2002). Although the MOU provides for, among other things, SCE to be entitled to sufficient revenue to cover its costs from January 2001 associated with retained generation and existing power contracts, the implementation of the MOU requires the CPUC to modify various decisions (discussed in Rate Stabilization Proceeding). Until the various regulatory and legislative actions necessary to implement the MOU or other actions that make such recovery probable, are taken, SCE is not able to conclude that the regulatory assets and liabilities related to purchased-power settlements, the unamortized loss on SCE's generating plant sales in 1998, and various other regulatory assets and liabilities (including income taxes previously flowed through to customers) related to certain generating assets are probable of recovery through the rate-making process. As a result, these balances were written off as a charge to earnings as of December 31, 2000 (see further discussion in Earnings).

During the rate freeze period, there are three sources of revenue available to SCE for transition cost recovery: revenue from the sale or valuation of generation assets in excess of book values, net market revenue from the sale of SCE-controlled generation into the ISO and PX markets, and competition transition charge (CTC) revenue. However, due to events discussed elsewhere in this report, revenue from the sale or valuation of generation assets in excess of book values (state legislation enacted in January 2001 bars the sale of SCE's remaining generation assets until 2006) and from the sale of SCE-controlled generation into the ISO and PX markets (see discussion in Generation and Power Procurement) are no longer available to SCE. During 1998, SCE sold all of its gas-fueled generation plants for $1.2 billion, over $500 million more than the combined book value. Net proceeds of the sales were used to reduce transition costs, which otherwise were expected to be collected through the TCBA mechanism.

Net market revenue from sales of power and capacity from SCE-controlled generation sources was also applied to transition cost recovery. Increases in market prices for electricity affected SCE in two fundamental ways prior to the CPUC's March 27, 2001, rate stabilization decision. First, CTC revenue decreased because there was less or no residual revenue from frozen rates due to higher cost PX and ISO power purchases. Second, transition costs decreased because there was increased net market revenue due to sales from SCE-controlled generation sources to the PX at higher prices (accumulated as an overcollection in the coal and hydroelectric balancing accounts). Although the second effect mitigated the first to some extent, the overall impact on transition cost recovery was negative because SCE purchased more power than it sold to the PX. In addition, higher market prices for electricity adversely affected SCE's ability to recover nontransition costs during the rate freeze period. Since May 2000, market prices for electricity were extremely high and there was insufficient revenue from customers under the frozen rates to cover all costs of providing service during that period, and therefore there was no positive residual CTC revenue transferred into the TCBA.

CTC revenue is determined residually (i.e., CTC revenue is the residual amount remaining from monthly gross customer revenue under the rate freeze after subtracting the revenue requirements for transmission, distribution, nuclear decommissioning and public benefit programs, and ISO payments and power purchases from the PX and ISO). The CTC applies to all customers who are using or begin using utility services on or after the CPUC's 1995 restructuring decision date. Residual CTC revenue is calculated through the TRA mechanism. Under CPUC decisions in existence prior to March 27, 2001, positive residual CTC revenue (TRA overcollections) was transferred to the TCBA monthly; TRA undercollections were to remain in the TRA until they were offset by overcollections, or the rate freeze ended, whichever came first. Pursuant to the March 27, 2001, rate stabilization decision, both positive and negative residual CTC revenue is transferred to the TCBA on a monthly basis, retroactive to January 1, 1998 (see further discussion in Rate Stabilization Proceeding).

Upon recalculating the TCBA balance based on the new decision, SCE has received positive residual CTC revenue (TRA overcollections) of $4.7 billion to recover its transition costs from the beginning of the rate freeze (January 1, 1998) through April 2000. As a result of sustained higher market prices, SCE experienced the first month in which costs exceeded revenue in May 2000. Since then, SCE's costs to provide power have continued to exceed revenue from frozen rates and as a result, the cumulative positive residual CTC revenue flowing into the TCBA mechanism has been reduced from $4.7 billion to $1.4 billion as of December 31, 2000. The cumulative TCBA undercollection (as recalculated) is $2.9 billion as of December 31, 2000. A summary of the components of this cumulative undercollection is as follows:

In millions	
Transition costs recorded in the TCBA:	
QF and interutility costs	**$ 3,561**
Amortization of nuclear-related regulatory assets	**3,090**
Depreciation of plant assets	**577**
Other transition costs	**634**
Total transition costs	**7,862**
Revenue available to recover transition costs	**(4,984)**
Unrecovered transition costs	**$ 2,878**

Unless the regulatory and legislative actions required to implement the MOU or other actions that make such recovery probable, are taken, SCE is not able to conclude that the recalculated TCBA net undercollection is probable of recovery through the rate-making process. As a result, the $2.9 billion TCBA net undercollection was written off as a charge to earnings as of December 31, 2000 (see further discussion in Earnings). In its interim rate stabilization decision of March 27, 2001, the CPUC denied a December motion by SCE to end the rate freeze, and stated that it will not end until recovery of all specified transition costs (including TCBA undercollections as recalculated) or March 31, 2002. For more details on the matters discussed above, see Rate Stabilization Proceeding.

Litigation

In November 2000, SCE filed a lawsuit against the CPUC in federal court in California, seeking a ruling that SCE is entitled to full recovery of its past electricity procurement costs in accordance with the tariffs filed with the FERC. The effect of such a ruling would be to overturn the prior decisions of the CPUC restricting recovery of TRA undercollections. In January 2001, the court denied the CPUC's motion to dismiss the action and also denied SCE's motion for summary judgment without prejudice. In February 2001, the court denied SCE's motion for a preliminary injunction ordering the CPUC to institute rates sufficient to enable SCE to recover its past procurement costs, subject to refund. The court granted, in part, SCE's additional motion to specify certain material facts without substantial controversy, but denied the remainder of the motion and declined to declare at that time that SCE is entitled to recover the amount of its undercollected procurement costs. In March 2001, the court directed the parties to be prepared for trial on July 31, 2001. As discussed in the Memorandum of Understanding with the CDWR, after the other elements of the MOU are implemented, SCE will enter into a settlement of or dismiss its lawsuit against the CPUC seeking recovery of past undercollected costs. The settlement or dismissal will include related claims against the State of California or any of its agencies, or against the federal government. SCE cannot predict whether or when a favorable final judgment or other resolution would be obtained in this legal action, if it were to proceed to trial.

In December 2000, a first amended complaint to a class action securities lawsuit (originally filed in October 2000) was filed in federal district court in Los Angeles against SCE and Edison International. On March 5, 2001, a second amended complaint was filed that alleges that SCE and Edison International are engaging in fraud by over-reporting and improperly accounting for the TRA undercollections. The second amended complaint is supposedly filed on behalf of a class of persons who purchased Edison International common stock beginning June 1, 2000, and continuing until such time as TRA-related undercollections are recorded as a loss on SCE's income statement. The response to the second amended complaint was due April 2, 2001. The response has been deferred pending resolution of motions to consolidate this lawsuit with the March 15, 2001, lawsuit discussed below. SCE believes that its current and past accounting for the TRA undercollections and related items, as described above, is appropriate and in accordance with accounting principles generally accepted in the United States.

On March 15, 2001, a purported class action lawsuit was filed in federal district court in Los Angeles against Edison International and SCE and certain of their officers. The complaint alleges that the defendants engaged in securities fraud by misrepresenting and/or failing to disclose material facts concerning the financial condition of Edison International and SCE, including that the defendants allegedly over-reported income and improperly accounted for the TRA undercollections. The complaint is supposedly filed on behalf of a class of persons who purchased all publicly traded securities of Edison International between May 12, 2000, and December 22, 2000. Pursuant to an agreement with Edison International and SCE, this lawsuit is expected to be consolidated with the October 20, 2000, lawsuit discussed above, pending the court's approval.

In addition to the two lawsuits filed against SCE and discussed above, as of April 13, 2001, 17 additional lawsuits have been filed against SCE by QFs. The lawsuits have been filed by various parties, including geothermal or wind energy suppliers or owners of cogeneration projects. The lawsuits are seeking payments of at least $420 million for energy and capacity supplied to SCE under QF contracts, and in some cases for damages as well. Many of these QF lawsuits also seek an order allowing the suppliers to stop providing power to SCE and sell the power to other purchasers. SCE is seeking coordination of all of the QF-related lawsuits that have commenced in various California courts. On April 13, 2001, an order was issued assigning all pending cases to a coordination motion judge and setting a hearing on SCE's coordination petition by May 30, 2001. SCE cannot predict the outcome of any of these matters.

Rate Stabilization Proceeding

In January 2000, SCE filed an application with the CPUC proposing rates that would go into effect when the current rate freeze ends on March 31, 2002, or earlier, depending on the pace of transition cost recovery. On December 20, 2000, SCE filed an amended rate stabilization plan application, stating that the CPUC must recognize that the statutory rate freeze is now over in accordance with California law, and requesting the CPUC to approve an immediate 30% increase to be effective, subject to refund, January 4, 2001. SCE's plan included a trigger mechanism allowing for rate increases of 5% every six months if SCE's TRA undercollection balance exceeds $1 billion. Hearings were held in late December 2000.

On January 4, 2001, the CPUC issued an interim decision that authorized SCE to establish an interim surcharge of 1¢ per kWh for 90 days, subject to refund. The revenue from the surcharge is being tracked through a balancing account and applied to ongoing power procurement costs. The surcharge resulted in rate increases, on average, of approximately 7% to 25%, depending on the class of customer. As noted in the decision, the 90-day period allowed independent auditors engaged by the CPUC to perform a comprehensive review of SCE's financial position, as well as that of Edison International and other affiliates.

On January 29, 2001, independent auditors hired by the CPUC issued a report on the financial condition and solvency of SCE and its affiliates. The report confirmed what SCE had previously disclosed to the CPUC in public filings about SCE's financial condition. The audit report covers, among other things, cash needs, credit relationships, accounting mechanisms to track stranded cost recovery, the flow of funds between SCE and Edison International, and earnings of SCE's California affiliates. On April 3, 2001, the CPUC adopted an order instituting investigation (originally proposed on March 15, 2001). The order reopens past CPUC decisions authorizing the utilities to form holding companies and initiates an investigation into: whether the holding companies violated requirements to give priority to the capital needs of their respective utility subsidiaries; whether ring-fencing actions by Edison International and PG&E Corporation and their respective nonutility affiliates also violated the requirements to give priority to the capital needs of their utility subsidiaries; whether the payment of dividends by the utilities violated requirements that the utilities maintain dividend policies as though they were comparable stand-alone utility companies; any additional suspected violations of laws or CPUC rules and decisions; and whether additional rules, conditions, or other changes to the holding company decisions are necessary. An assigned commissioner's ruling on March 29, 2001, required Edison International and SCE to respond within 10 days to document requests and questions that are substantially identical to those included in the March 15 proposed order instituting investigation. The MOU calls for the CPUC to adopt a decision clarifying that the first priority condition in SCE's holding company decision refers to equity investment, not working capital for operating costs. Neither Edison International nor SCE can provide assurance that the CPUC will adopt such a decision, or predict what effects any investigation or any subsequent actions by the CPUC may have on either of them.

In its interim rate stabilization order adopted on March 27, 2001, the CPUC granted SCE a rate increase in the form of a 3¢ per kWh surcharge applied only to electric power costs, effective immediately, and affirmed that the 1¢ interim surcharge granted on January 4, 2001, is now permanent. Although the 3¢ increase was authorized immediately, the surcharge will not be collected in rates until the CPUC establishes an appropriate rate design, which is not expected to occur until May 2001. SCE has asked the CPUC to immediately adopt an interim rate increase that would allow the rate change to go into effect sooner. The CPUC also ordered that the 3¢ surcharge be added to the rate paid to the CDWR pursuant to the interim CDWR-related decision (see CDWR Power Purchases).

Also, in the interim order, the CPUC granted a petition previously filed by The Utility Reform Network and directed that the balance in SCE's TRA, whether over- or undercollected, be transferred on a monthly basis to the TCBA, retroactive to January 1, 1998. Previous rules called only for TRA overcollections (residual CTC revenue) to be transferred to the TCBA. The CPUC also ordered SCE to transfer the coal and hydroelectric balancing account overcollections to the TRA on a monthly basis before any transfer of residual CTC revenue to the TCBA, retroactive to January 1, 1998. Previous rules called for overcollections in these two balancing accounts to be transferred directly to the TCBA on an annual basis (see further discussion of the recalculation of the TCBA in Status of Transition and Power Procurement Costs Recovery). SCE believes this interim order attempts to retroactively transform power purchase costs in the TRA into transition costs in the TCBA. However, the CPUC characterized the accounting changes as merely reducing the prior residual CTC revenue recorded in the TCBA, thus only affecting the amount of transition cost recovery achieved to date. Based upon the transfer of balances into the TCBA, the CPUC denied SCE's December 2000 filing to have the current rate freeze end, and stated that it will not end until recovery of all specified transition costs or March 31, 2002; and that balances in the TRA cannot be recovered after the end of the rate freeze. The CPUC also said that it would monitor the balances remaining in the TCBA and consider how to address remaining balances in the ongoing proceeding. If the CPUC does not modify this decision in a manner consistent with the MOU, SCE intends to challenge this decision through all appropriate means.

Although the CPUC has authorized a substantial rate increase in its March 27, 2001, order, it has allocated the revenue from the increase entirely to future purchased-power costs without addressing SCE's past undercollections for the costs of purchased power. The CPUC's decisions do not assure that SCE will be able to meet its ongoing obligations or repay past due obligations. By ordering immediate payments to the CDWR and QFs, the CPUC aggravated SCE's cash flow and liquidity problems. Additionally, the CPUC expressed the view that AB 1X continues the utilities' obligations to serve their customers, and stated that it cannot assume that the CDWR will purchase all the electricity needed above what the utilities either generate or have under contract (the net short position) and cannot order the CDWR to do so. This could result in additional purchased power costs with no allowed means of recovery. To implement the MOU, it will be necessary for the CPUC to modify or rescind these decisions. SCE cannot provide any assurance that the CPUC will do so.

Accounting for Generation-Related Assets and Power Procurement Costs

In 1997, SCE discontinued application of accounting principles for rate-regulated enterprises for its generation assets. At that time, SCE did not write off any of its generation-related assets, including related regulatory assets, because the electric utility industry restructuring plan made probable their recovery through a nonbypassable charge to distribution customers.

During the second quarter of 1998, in accordance with asset impairment accounting standards, SCE reduced its remaining nuclear plant investment by $2.6 billion (as of June 30, 1998) and recorded a regulatory asset on its balance sheet for the same amount. For this impairment assessment, the fair value of the investment was calculated by discounting expected future net cash flows. This reclassification had no effect on SCE's results of operations.

The implementation of the MOU requires various regulatory and legislative actions to be taken in the future. Unless those actions or other actions that make such recovery probable are taken which would include modifying or reversing recent CPUC decisions that impair recovery of SCE's power procurement and transition costs, SCE is not able to conclude that its $2.9 billion TCBA undercollection (as redefined in the March 27 decisions) and $1.3 billion (book value) of its generation-related regulatory assets and liabilities to be amortized into the TCBA, are probable of recovery through the rate-making process. As a result, accounting principles generally accepted in the United States require that the balances in the accounts be written off as a charge to earnings as of December 31, 2000 (see Earnings).

As discussed below, an MOU has been negotiated with representatives of the Governor as a step to resolving the energy crisis. The regulatory and legislative actions set forth in the MOU, if implemented, are expected to result in a rate-making mechanism that would make recovery of these regulatory assets probable. If and when those actions or other actions occur that make such recovery probable are taken, and the necessary rate-making mechanism is adopted, the regulatory assets would be restored to the balance sheet, with a corresponding increase to earnings.

Memorandum of Understanding with the CDWR

On April 9, 2001, Edison International and SCE signed an MOU with the CDWR regarding the California energy crisis and its effects on SCE. The Governor of California and his representatives participated in the negotiation of the MOU, and the Governor endorsed implementation of all the elements of the MOU. The MOU sets forth a comprehensive plan calling for legislation, regulatory action and definitive agreements to resolve important aspects of the energy crisis, and which, if implemented, is expected to help restore SCE's creditworthiness and liquidity. Key elements of the MOU include:

- SCE will sell its transmission assets to the CDWR, or another authorized California state agency, at a price equal to 2.3 times their aggregate book value, or approximately $2.76 billion. If a sale of the transmission assets is not completed under certain circumstances, SCE's hydroelectric assets and other rights may be sold to the state in their place. SCE will use the proceeds of the sale in excess of book value to reduce its undercollected costs and retire outstanding debt incurred in financing those costs. SCE will agree to operate and maintain the transmission assets for at least three years, for a fee to be negotiated.

- Two dedicated rate components will be established to assist SCE in recovering the net undercollected amount of its power procurement costs through January 31, 2001, estimated to be approximately $3.5 billion. The first dedicated rate component will be used to securitize the excess of the undercollected amount over the expected gain on sale of SCE's transmission assets, as well as certain other costs. Such securitization will occur as soon as reasonably practicable after passage of the necessary legislation and satisfaction of other conditions of the MOU. The second dedicated rate component would not be securitized and would not appear in rates unless the transmission sale failed to close within a two-year period. The second component is designed to allow SCE to obtain bridge financing of the portion of the undercollection intended to be recovered through the gain on the transmission sale.

- SCE will continue to own its generation assets, which will be subject to cost-based ratemaking, through 2010. SCE will be entitled to collect revenue sufficient to cover its costs from January 1, 2001, associated with the retained generation assets and existing power contracts. The MOU calls for the CPUC to adopt cost recovery mechanisms consistent with SCE obtaining and maintaining an investment grade credit rating.

- The CDWR will assume the entire responsibility for procuring the electricity needs of retail customers within SCE's service territory through December 31, 2002, to the extent that those needs are not met by generation sources owned by or under contract to SCE. (The unmet needs are referred to as SCE's net short position.) SCE will resume procurement of its net short position after 2002. The MOU calls for the CPUC to adopt cost recovery mechanisms to make it financially practicable for SCE to reassume this responsibility.

- SCE's authorized return on equity will not be reduced below its current level of 11.6% before December 31, 2010. Through the same date, a rate-making capital structure for SCE will not be established with different proportions of common equity or preferred equity to debt than set forth in current authorizations. These measures are intended to enable SCE to achieve and maintain an investment grade credit rating.

- Edison International and SCE will commit to make capital investments in SCE's regulated businesses of at least $3 billion through 2006, or a lesser amount approved by the CPUC. The equity component of the investments will be funded from SCE's retained earnings or, if necessary, from equity investments by Edison International.

- EME will execute a contract with the CDWR or another state agency for the provision of power to the state at cost-based rates for 10 years from a power project currently under development. EME will use all commercially reasonable efforts to place the first phase of the project into service before the end of summer 2001.

- SCE will grant perpetual conservation easements over approximately 21,000 acres of lands associated with SCE's Big Creek and Eastern Sierra hydroelectric facilities. The easements initially will be held by a trust for the benefit of the State of California, but ultimately may be assigned to nonprofit entities or certain governmental agencies. SCE will be permitted to continue utility uses of the subject lands.

- After the other elements of the MOU are implemented, SCE will enter into a settlement of or dismiss its federal district court lawsuit against the CPUC seeking recovery of past undercollected costs. The settlement or dismissal will include related claims against the State of California or any of its agencies, or against the federal government.

The sale of SCE's transmission system and other elements of the MOU must be approved by the FERC. Edison International, SCE and the CDWR committed in the MOU to proceed in good faith to sponsor and support the required legislation and to negotiate in good faith the necessary definitive agreements. The MOU may be terminated by either SCE or the CDWR if required legislation is not adopted and definitive agreements executed by August 15, 2001, or if the CPUC does not adopt required implementing decisions within 60 days after the MOU was signed, or if certain other adverse changes occur. Edison International and SCE cannot provide assurance that all the required legislation will be enacted, regulatory actions taken, and definitive agreements executed before the applicable deadlines.

Distribution

Revenue related to distribution operations is determined through a performance-based rate-making (PBR) mechanism and the distribution assets have the opportunity to earn a CPUC-authorized 9.49% return on investment. The distribution PBR will extend through December 2001. Key elements of the distribution PBR include: distribution rates indexed for inflation based on the Consumer Price Index less a productivity factor; adjustments for cost changes that are not within SCE's control; a cost-of-capital trigger mechanism based on changes in a utility bond index; standards for customer satisfaction; service reliability and safety; and a net revenue-sharing mechanism that determines how customers and shareholders will share gains and losses from distribution operations.

Transmission

Transmission revenue is determined through FERC-authorized rates and is subject to refund.

Wholesale Electricity Markets

In October 2000, SCE filed a joint petition urging the FERC to immediately find the California wholesale electricity market to be not workably competitive; immediately impose a cap on the price for energy and ancillary services; and institute further expedited proceedings regarding the market failure, mitigation of market power, structural solutions and responsibility for refunds. On December 15, 2000, the FERC released a final order containing remedies and other actions in response to the problems in the California electricity market. The order, among other things, eliminated the requirement for California utilities to buy and sell power exclusively through the ISO and PX; created a benchmark price for wholesale bilateral power contracts; created penalties for under-scheduling power loads; provided for an independent governing board for the ISO; and established a breakpoint of $150/MWh so that bids below $150 may clear at a single market-clearing price at or below $150/MWh and bids above $150 will be paid as bid. On December 18, 2000, SCE filed with the FERC an emergency request for rehearing and expedited action seeking reconsideration of the December 15 order. On January 12, 2001, the FERC issued an order granting rehearing for the purpose of further consideration. The PX did not immediately implement the $150/MWh breakpoint and on February 26, 2001, made a compliance filing with the FERC, which requested the FERC's guidance on an acceptable recalculation methodology. On April 6, 2001, the FERC issued an order providing guidance to the PX, which should reduce SCE's energy costs owed to the PX for the month of January 2001.

On December 13, 2000, the ISO announced that generators of electricity were refusing to sell into the California market due to concerns about the financial stability of SCE and Pacific Gas and Electric Company. In response to this announcement, on December 14, 2000, the United States Secretary of Energy issued an order requiring power companies to make arrangements to generate and deliver electricity as requested by the ISO after the ISO certifies that it has been unable to acquire adequate supplies of electricity in the market. After being renewed multiple times, the order expired on February 6, 2001. However, on February 7, 2001, a federal court judge issued a temporary restraining order requiring power suppliers to sell to the California grid. On March 21, 2001, a federal court judge ordered one of the power suppliers to continue to sell power to the California grid. Three other power suppliers have signed an agreement with the judge voluntarily agreeing to continue to sell power to the grid while awaiting a review of the issue by the FERC. On April 6, 2001, the United States Court of Appeals issued a stay order, suspending the lower court's March 21 order until a final appeals ruling can be issued.

On December 26, 2000, SCE filed an emergency petition in the federal Court of Appeals challenging the FERC order and seeking a writ of mandamus requiring the FERC to immediately establish cost-based wholesale rates. On January 5, 2001, the court denied SCE's petition. The effect of the denial is to leave in place the FERC's market controls that have allowed wholesale prices to climb to current levels. SCE's petition for rehearing remains pending. SCE cannot predict what action the FERC may take. SCE is considering the possibility of judicial appeals and other actions.

On March 9, 2001, the FERC directed 13 wholesale sellers of energy to refund $69 million or submit cost-of-service information to the FERC to justify their prices above $273/MWh during ISO Stage 3 emergencies in January 2001. SCE will oppose the order as inadequate, particularly because the FERC is unwilling to exercise any control over the sellers' exercise of market power during periods other than Stage 3 emergencies. On March 16, 2001, the FERC ordered six wholesale sellers of energy to refund an additional $55 million or submit cost-of-service information to the FERC to justify their prices above $430/MWh during ISO Stage 3 emergencies in February 2001. A Stage 3 emergency refers to 1.5% or less in reserve power, which could trigger rotating blackouts in some neighborhoods.

Environmental Protection

Edison International 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.

As further discussed in Note 12 to the Consolidated Financial Statements, Edison International records its environmental liabilities when site assessments and/or remedial actions are probable and a range of reasonably likely cleanup costs can be estimated. Edison International's recorded estimated minimum liability to remediate its 44 identified sites is $114 million. Edison International believes that, due to uncertainties inherent in the estimation process, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $272 million. In 1998, SCE sold all of its gas-fueled power plants but has retained some liability associated with the divested properties.

The CPUC allows SCE to recover environmental-cleanup costs at certain sites, representing $45 million of its recorded liability, through an incentive mechanism, which is discussed in Note 12. SCE has recorded a regulatory asset of $75 million for its estimated minimum environmental-cleanup costs expected to be recovered through customer rates.

Edison International's identified sites include several sites for which there is a lack of currently available information. As a result, no reasonable estimate of cleanup costs can be made for these sites. Edison International 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 $5 million to $15 million. Recorded costs for 2000 were $13 million.

Based on currently available information, Edison International believes it is unlikely that it will incur amounts in excess of the upper limit of the estimated range and, based upon the CPUC's regulatory treatment of environmental-cleanup costs, Edison International 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.

The Clean Air Act requires power producers to have emissions allowances to emit sulfur dioxide. Power companies receive emissions allowances from the federal government and may bank or sell excess allowances. SCE expects to have excess allowances under Phase II of the Clean Air Act (2000 and later). A study was undertaken to determine the specific impact of air contaminant emissions from the Mohave Generating Station on visibility in Grand Canyon National Park. The final report on this study, which was issued in March 1999, found negligible correlation between measured Mohave station tracer concentrations and visibility impairment. The absence of any obvious relationship cannot rule out Mohave station contributions to haze in Grand Canyon National Park, but strongly suggests that other sources were primarily responsible for the haze. In June 1999, the Environmental Protection Agency (EPA) issued an advanced notice of proposed rulemaking regarding assessment of visibility impairment at the Grand Canyon. SCE filed comments on the proposed rulemaking in November 1999. In 1998, several environmental groups filed suit against the co-owners of the Mohave station regarding alleged violations of emissions limits. In order to accelerate resolution of key environmental issues regarding the plant, the parties filed, in concurrence with SCE and the other station owners, a consent decree, which was approved by the court in December 1999. In a letter to SCE, the EPA has expressed its belief that the controls provided in the consent decree will likely resolve the potential Clean Air Act visibility concerns. The EPA is considering incorporating the decree into the visibility provisions of its Federal Implementation Plan for Nevada.

Edison International's projected environmental capital expenditures are $1.8 billion for the 2001-2005 period, mainly for undergrounding certain transmission and distribution lines at SCE and upgrading environmental controls at EME.

San Onofre Nuclear Generating Station

On February 3, 2001, SCE's San Onofre Unit 3 experienced a fire due to an electrical fault in the non-nuclear portion of the plant. The turbine rotors, bearings and other components of the turbine generator system were damaged extensively. SCE expects that Unit 3 will return to service sometime in mid-June 2001. SCE anticipates that its lost revenue under the currently effective San Onofre recovery plan (discussed in the Generation and Power Procurement section of SCE's Regulatory Environment) will be approximately $100 million.

The San Onofre Units 2 and 3 steam generators' design allows for the removal of up to 10% of the tubes before the rated capacity of the unit must be reduced. Increased tube degradation was found during routine inspections in 1997. To date, 8% of Unit 2's tubes and 6% of Unit 3's tubes have been removed from service. A decreasing (favorable) trend in degradation has been observed in more recent inspections.

Accounting Changes

On January 1, 2001, Edison International adopted a new accounting standard for derivative instruments and hedging activities. The new standard requires all derivatives be recognized on the balance sheet at fair value. Gains or losses from changes in fair value would be recognized in earnings in the period of change unless the derivative is designated as a hedging instrument. Gains or losses from hedges of a forecasted transaction or foreign currency exposure would be recorded as a separate component of shareholders' equity under the caption "Accumulated other comprehensive income." Gains or losses from hedges of a recognized asset or liability or a firm commitment would be reflected in earnings for the ineffective portion of the hedge. SCE's derivatives qualify for hedge accounting under the new standard. SCE does not anticipate any earnings impact from its derivatives, since it expects that any market price changes will be recovered in rates. As a result of the adoption of the new standard, Edison International expects that the quarterly earnings from its EME subsidiary will be more volatile than earnings reported under the prior accounting policy. For Edison International's 2001 earnings, the cumulative effect on prior years resulting from the adoption of the new standard is expected to be less than $10 million (after tax).

Effective January 1, 2000, EME changed its accounting method for major maintenance to record such expenses as incurred. Previously, EME recorded major maintenance costs on an accrue-in-advance method. EME voluntarily made the change in accounting due to guidance provided by the Securities and Exchange Commission. The cumulative effect of the change in accounting method was an $18 million after-tax benefit.

On January 1, 1999, Edison International implemented a new accounting rule that requires costs related to start-up activities to be expensed as incurred. Although this new accounting rule did not materially affect Edison International's results of operations or financial position, EME wrote off $14 million (after tax) of previously capitalized start-up costs in first quarter 1999.

Forward-Looking Information

In the preceding Management's Discussion and Analysis of Results of Operations and Financial Condition and elsewhere in this annual report, the words estimates, expects, anticipates, believes and other similar expressions are intended to identify forward-looking information that involves risks and uncertainties. Actual results or outcomes could differ materially as a result of such important factors as implementation (or nonimplementation) of the MOU as described above; the outcome of negotiations for solutions to SCE's liquidity problems; further actions by state and federal regulatory bodies setting rates, adopting or modifying cost recovery, accounting or rate-setting mechanisms and implementing the restructuring of the electric utility industry; actions by lenders, investors and creditors in response to SCE's suspension of payments for debt service and purchased power, including the possible filing of an involuntary bankruptcy petition against SCE; the effects, unfavorable interpretations and applications of new or existing laws and regulations relating to restructuring, taxes and other matters; the effects of increased competition in energy-related businesses; changes in prices of electricity and fuel costs; the actions of securities rating agencies; the availability of credit, including Edison International's and SCE's ability to regain an investment grade rating and re-enter the credit markets; changes in financial market conditions; risks of doing business in foreign countries, such as political changes and currency devaluations; power plant construction and operation risks; new or increased environmental liabilities; the amount of revenue available to recover both transition and nontransition costs; the financial viability of new businesses, such as telecommunications; weather conditions; and other unforeseen events.

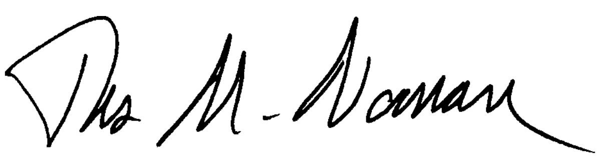
The management of Edison International is responsible for the integrity and objectivity of the accompanying financial statements. The statements have been prepared in accordance with accounting principles generally accepted in the United States and are based, in part, on management estimates and judgment.

Edison International and its subsidiaries maintain systems of internal control to provide reasonable, but not absolute, assurance that assets are safeguarded, transactions are executed in accordance with management's authorization and the accounting records may be relied upon for the preparation of the financial statements. There are limits inherent in all systems of internal control, the design of which involves management's judgment and the recognition that the costs of such systems should not exceed the benefits to be derived. Edison International believes its systems of internal control achieve this appropriate balance. These systems are augmented by internal audit programs through which the adequacy and effectiveness of internal controls and policies and procedures are monitored, evaluated and reported to management. Actions are taken to correct deficiencies as they are identified.

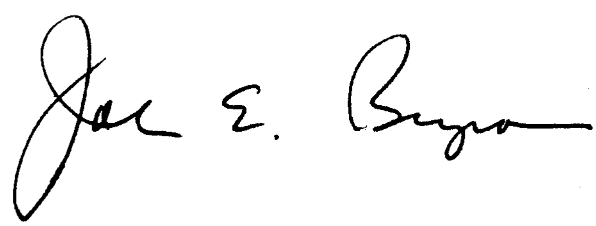
Edison International's independent public accountants, Arthur Andersen LLP, are engaged to audit the financial statements in accordance with auditing standards generally accepted in the United States and to express an informed opinion on the fairness, in all material respects, of Edison International's reported results of operations, cash flows and financial position.

As a further measure to assure the ongoing objectivity of financial information, the audit committee of the Board of Directors, which is composed of outside directors, meets periodically, both jointly and separately, with management, the independent public accountants and internal auditors, who have unrestricted access to the committee. The committee recommends annually to the Board of Directors the appointment of a firm of independent public accountants to conduct audits of its financial statements; considers the independence of such firm and the overall adequacy of the audit scope and Edison International's systems of internal control; reviews financial reporting issues and is advised of management's actions regarding financial reporting and internal control matters.

Edison International and its subsidiaries maintain high standards in selecting, training and developing personnel to assure that their operations are conducted in conformity with applicable laws and are committed to maintaining the highest standards of personal and corporate conduct. Management maintains programs to encourage and assess compliance with these standards.



Thomas M. Noonan
Vice President
and Controller



John E. Bryson
Chairman of the Board, President
and Chief Executive Officer

April 12, 2001

Report of Independent Public Accountants

To the Shareholders and the Board of Directors, Edison International:

We have audited the accompanying consolidated balance sheets of Edison International (a California corporation) and its subsidiaries as of December 31, 2000, and 1999, and the related consolidated statements of income (loss), comprehensive income (loss), cash flows and changes in common shareholders' equity for each of the three years in the period ended December 31, 2000. These financial statements are the responsibility of Edison International's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the 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. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Edison International and its subsidiaries as of December 31, 2000, and 1999, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States.

ARTHUR ANDERSEN LLP

Los Angeles, California
April 12, 2001

In millions, except per share amounts Year ended December 31,	2000	1999	1998
Electric utility	**$ 7,870**	$7,548	$7,499
Nonutility power generation	**3,253**	1,642	894
Financial services and other	**594**	506	467
Total operating revenue	**11,717**	9,696	8,860
Fuel	**1,277**	664	501
Purchased power — contracts	**2,357**	2,419	2,626
Purchased power — PX/ISO — net	**2,329**	771	636
Provisions for regulatory adjustment clauses — net	**2,301**	(763)	(473)
Other operation and maintenance	**3,145**	2,935	2,533
Depreciation, decommissioning and amortization	**1,933**	1,795	1,662
Property and other taxes	**129**	124	133
Net gain on sale of utility plant	**(25)**	(3)	(542)
Total operating expenses	**13,446**	7,942	7,076
Operating income (loss)	**(1,729)**	1,754	1,784
Interest and dividend income	**227**	96	108
Other nonoperating income	**165**	195	140
Interest expense — net of amounts capitalized	**(1,388)**	(894)	(710)
Other nonoperating deductions	**(146)**	(164)	(154)
Dividends on preferred securities	**(100)**	(44)	(13)
Dividends on utility preferred stock	**(21)**	(26)	(25)
Income (loss) before taxes	**(2,992)**	917	1,130
Income taxes	**(1,049)**	294	462
Net income (loss)	**$(1,943)**	$ 623	$ 668
Weighted average shares of common stock outstanding	**333**	348	359
Basic earnings (loss) per share	**$ (5.84)**	$ 1.79	$ 1.86
Weighted average shares, including effect of dilutive securities	**333**	349	364
Diluted earnings (loss) per share	**$ (5.84)**	$ 1.79	$ 1.84
Dividends declared per common share	**$ 0.84**	$ 1.08	$ 1.04

Consolidated Statements of Comprehensive Income (Loss)

In millions Year ended December 31,	2000	1999	1998
Net income (loss)	**$(1,943)**	$ 623	$ 668
Cumulative translation adjustments — net	**(150)**	(19)	—
Unrealized gain (loss) on securities — net	**(7)**	23	12
Reclassification adjustment for gains included in net income	**(24)**	(46)	(18)
Comprehensive income (loss)	**$(2,124)**	$ 581	$ 662

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

Consolidated Balance Sheets

In millions December 31,	2000	1999
Assets		
Cash and equivalents	**$ 1,973**	$ 508
Receivables, less allowances of $40 and $34 for uncollectible accounts at respective dates	**1,099**	944
Accrued unbilled revenue	**377**	434
Fuel inventory	**220**	241
Materials and supplies, at average cost	**210**	199
Accumulated deferred income taxes — net	**1,350**	191
Trading and price risk management assets	**252**	—
Prepayments and other current assets	**185**	153
Total current assets	**5,666**	2,670
Nonutility property — less accumulated provision for depreciation of $774 and $446 at respective dates	**10,084**	12,352
Nuclear decommissioning trusts	**2,505**	2,509
Investments in partnerships and unconsolidated subsidiaries	**2,700**	2,505
Investments in leveraged leases	**2,345**	1,885
Other investments	**92**	180
Total investments and other assets	**17,726**	19,431
Utility plant, at original cost:		
Transmission and distribution	**13,129**	12,439
Generation	**1,745**	1,718
Accumulated provision for depreciation and decommissioning	**(7,834)**	(7,520)
Construction work in progress	**636**	562
Nuclear fuel, at amortized cost	**143**	132
Total utility plant	**7,819**	7,331
Regulatory assets — net	**2,390**	5,555
Other deferred charges	**1,499**	1,242
Total deferred charges	**3,889**	6,797
Total assets	**$35,100**	$36,229

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

In millions, except share amounts December 31,	2000	1999
Liabilities and Shareholders' Equity		
Short-term debt	**$ 3,920**	$ 2,553
Current portion of long-term debt	**2,260**	962
Accounts payable	**1,228**	625
Accrued taxes	**593**	407
Accrued interest	**232**	189
Dividends payable	**12**	101
Regulatory liabilities — net	**195**	101
Trading and price risk management liabilities	**282**	—
Deferred unbilled revenue	**250**	300
Other current liabilities	**1,828**	1,604
Total current liabilities	**10,800**	6,842
Long-term debt	**12,150**	13,391
Accumulated deferred income taxes — net	**5,328**	5,757
Accumulated deferred investment tax credits	**183**	225
Customer advances and other deferred credits	**1,692**	2,094
Power purchase contracts	**466**	563
Accumulated provision for pensions and benefits	**439**	374
Other long-term liabilities	**94**	104
Total deferred credits and other liabilities	**8,202**	9,117
Commitments and contingencies (Notes 2, 3, 11 and 12)		
Minority interest	**18**	9
Preferred stock of utility:		
Not subject to mandatory redemption	**129**	129
Subject to mandatory redemption	**256**	256
Company-obligated mandatorily redeemable securities of subsidiaries holding solely parent company debentures	**949**	948
Other preferred securities	**176**	326
Total preferred securities of subsidiaries	**1,510**	1,659
Common stock (325,811,206 and 347,207,106 shares outstanding at respective dates)	**1,960**	2,090
Accumulated other comprehensive income:		
Cumulative translation adjustments — net	**(139)**	11
Unrealized gain in equity securities — net	**—**	31
Retained earnings	**599**	3,079
Total common shareholders' equity	**2,420**	5,211
Total liabilities and shareholders' equity	**$35,100**	$36,229

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

Consolidated Statements of Cash Flows

In millions Year ended December 31,	**2000**	1999	1998
Cash flows from operating activities:			
Net income (loss)	**$(1,943)**	$ 623	$ 668
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, decommissioning and amortization	**1,933**	1,795	1,662
Other amortization	**168**	112	96
Deferred income taxes and investment tax credits	**(1,086)**	525	348
Equity in income from partnerships and unconsolidated subsidiaries	**(267)**	(244)	(190)
Income from leveraged leases	**(192)**	(214)	(213)
Regulatory balancing accounts — long-term	**1,758**	(1,354)	(361)
Net gain on sale of utility generating plants	**(14)**	(1)	(565)
Net gain on sale of marketable securities	**(57)**	(77)	(30)
Other assets	**54**	(58)	(244)
Other liabilities	**(132)**	134	49
Changes in working capital:			
Receivables	**(140)**	(75)	(235)
Regulatory balancing accounts — short-term	**97**	363	(94)
Fuel inventory, materials and supplies	**30**	(5)	24
Prepayments and other current assets	**12**	(75)	(19)
Accrued interest and taxes	**204**	(151)	68
Accounts payable and other current liabilities	**757**	526	283
Distributions and dividends from unconsolidated entities	**227**	213	185
Net cash provided by operating activities	**1,409**	2,037	1,432
Cash flows from financing activities:			
Long-term debt issued	**5,600**	6,685	981
Long-term debt repaid	**(4,608)**	(1,071)	(1,544)
Bonds repurchased and funds held in trust	**(440)**	—	—
Common stock repurchased	**(386)**	(92)	(714)
Preferred securities issued	**—**	1,124	—
Preferred stocks redeemed	**(125)**	—	(74)
Rate reduction notes repaid	**(246)**	(246)	(252)
Short-term debt financing — net	**1,324**	1,931	236
Dividends paid	**(371)**	(373)	(374)
Nuclear fuel financing — net	**9**	(37)	17
Net cash provided (used) by financing activities	**757**	7,921	(1,724)
Cash flows from investing activities:			
Additions to property and plant	**(1,488)**	(1,232)	(963)
Acquisition of nonutility property	**(47)**	(7,958)	(258)
Proceeds from sale of nonutility property	**1,727**	115	1,215
Funding of nuclear decommissioning trusts	**(69)**	(116)	(163)
Investments in partnerships and unconsolidated subsidiaries	**(289)**	(853)	(401)
Investments in leveraged leases	**(255)**	(99)	(458)
Proceeds from sales of marketable securities	**58**	84	32
Investments in other assets	**(302)**	28	(32)
Net cash used by investing activities	**(665)**	(10,031)	(1,028)
Effect of exchange rate changes on cash	**(36)**	(3)	(3)
Net increase (decrease) in cash and equivalents	**1,465**	(76)	(1,323)
Cash and equivalents, beginning of year	**508**	584	1,907
Cash and equivalents, end of year	**$ 1,973**	$ 508	$ 584

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

In millions, except share amounts	Common Stock	Accumulated Other Comprehensive Income	Retained Earnings	Total Common Shareholders' Equity
Balance at December 31, 1997	$2,261	$ 90	$ 3,176	$ 5,527
Net income			668	668
Stock repurchase and retirement (25,211,232 shares)	(152)		(562)	(714)
Dividends declared on common stock			(371)	(371)
Unrealized gain on securities		18		18
Tax effect		(6)		(6)
Reclassified adjustment for gain included in net income		(30)		(30)
Tax effect		12		12
Stock option appreciation			(5)	(5)
Balance at December 31, 1998	2,109	84	2,906	5,099
Net income			623	623
Stock repurchase and retirement (3,350,500 shares)	(20)		(72)	(92)
Dividends declared on common stock			(375)	(375)
Unrealized gain on securities		39		39
Tax effect		(16)		(16)
Reclassified adjustment for gain included in net income		(77)		(77)
Tax effect		31		31
Cumulative translation adjustment		(21)		(21)
Tax effect		2		2
Capital stock expense	1			1
Stock option appreciation			(3)	(3)
Balance at December 31, 1999	2,090	42	3,079	5,211
Net income (loss)			(1,943)	(1,943)
Stock repurchase and retirement (21,402,700 shares)	(130)		(257)	(387)
Dividends declared on common stock			(277)	(277)
Unrealized gain on securities		(11)		(11)
Tax effect		4		4
Reclassified adjustment for gain included in net income		(41)		(41)
Tax effect		17		17
Cumulative translation adjustment		(148)		(148)
Tax effect		(2)		(2)
Stock option appreciation			(3)	(3)
Balance at December 31, 2000	**$1,960**	**$(139)**	**$ 599**	**$ 2,420**

Authorized common stock is 800 million shares with no par value.

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

Note 1. Summary of Significant Accounting Policies

Nature of Operations

Edison International's wholly owned subsidiaries include: Southern California Edison Company (SCE), a rate-regulated electric utility which supplies electric energy for its 4.3 million customers in central, coastal and Southern California; Edison Mission Energy (EME), a producer of electricity engaged in the development, acquisition, ownership or leasing and operation of electric power generation facilities worldwide; Edison Capital, a provider of capital and financial services; and Edison Enterprises, the retail business arm of Edison International. EME and Edison Capital have domestic and foreign projects, primarily in Europe, Asia, Australia and Africa.

EME's plants are located in different geographic areas, mitigating the effects of regional markets, economic downturns or unusual weather conditions. EME's domestic projects (other than Homer City and the Illinois plants) generally sell power to a limited number of electric utilities under long-term (15 years to 30 years) contracts. Projects in both the United Kingdom and Australia sell their energy and capacity through a centralized electricity pool. A project in New Zealand sells its power through a voluntary pool system. Other electric power generated overseas is sold primarily through long-term contracts to electric utilities in the country where the power is generated. EME also conducts energy trading and price risk management activities in power markets open to competition.

SCE operates in a highly regulated environment in which it has an obligation to deliver electric service to customers in return for an exclusive franchise within its service territory. In 1996, state lawmakers and the California Public Utilities Commission (CPUC) initiated the electric industry restructuring process. SCE was directed by the CPUC to divest the bulk of its generation portfolio. Today, those generating plants are owned by independent power companies. Along with electric industry restructuring, a multi-year freeze on the rates that SCE could charge its customers was mandated and transition cost recovery mechanisms allowing SCE to recover its stranded costs associated with generation-related assets were implemented. California's electric industry restructuring statute included provisions to finance a portion of the stranded costs that residential and small commercial customers would have paid between 1998 and 2001, which allowed SCE to reduce rates by at least 10% to these customers, effective January 1, 1998. These frozen rates are to remain in effect until the earlier of March 31, 2002, or the date when the CPUC-authorized costs for utility-owned generation assets and obligations are recovered. However, since the summer of 2000, the prices charged by generators and other sellers have escalated far beyond what SCE can currently charge its customers. See Note 3 for a further discussion.

SCE also produces electricity. On April 1, 1998, SCE began selling all of its electric generation through the California Power Exchange (PX) and Independent System Operator (ISO) and scheduling delivery through the ISO, as mandated by the CPUC's 1995 restructuring decision. By purchasing wholesale electricity through the PX and ISO, SCE satisfied the electric energy needs for customers who did not choose an alternative energy provider. The Federal Energy Regulatory Commission (FERC) issued an order on December 15, 2000, which, among other things, eliminated the requirement for California utilities to buy and sell power exclusively through the ISO and PX. On January 19, 2001, the PX announced that it will permanently cease operations by April 2001; on March 9, 2001, the PX filed for Chapter 11 bankruptcy protection.

The CPUC regulates SCE's capital structure, limiting the dividends it may pay Edison International. In light of SCE's liquidity crisis, its Board of Directors did not declare quarterly common stock dividends to its parent, Edison International in either December 2000 or March 2001. Edison International's Board of Directors also did not declare common stock dividends that would have been paid to its shareholders. See Note 2 for a further discussion.

Basis of Presentation

The consolidated financial statements include Edison International and its wholly owned subsidiaries. Edison International's subsidiaries use the equity method to account for significant investments in partnerships and subsidiaries in which they own 50% or less. Intercompany transactions have been eliminated, except EME's profits from energy sales to SCE, which are allowed in utility rates. Certain prior-year amounts were reclassified to conform to the December 31, 2000, financial statement presentation.

SCE's accounting policies conform with accounting principles generally accepted in the United States, including the accounting principles for rate-regulated enterprises, which reflect the rate-making policies of the CPUC and the FERC. Since 1997, SCE has used accounting principles applicable to enterprises in general for its investment in generation facilities, as a result of industry restructuring legislation enacted by the State of California and related changes in the rate-recovery of generation-related assets. Application of such accounting principles to SCE's generation assets did not result in any adjustment of their carrying value.

Earnings (Loss) Per Share (EPS)

Basic EPS is computed by dividing net income (loss) by the weighted-average number of common shares outstanding. In arriving at net income (loss), dividends on preferred securities and preferred stock have been deducted. For the diluted EPS calculation, dilutive securities (employee stock options) are added to the weighted-average shares. In 2000, the dilutive securities were excluded from the diluted EPS calculation due to their antidilutive effect.

Estimates

Financial statements prepared in compliance with accounting principles generally accepted in the United States require management to make estimates and assumptions that affect the amounts reported in the financial statements and disclosure of contingencies. Actual results could differ from those estimates. Certain significant estimates related to liquidity, electric utility regulatory matters, decommissioning and contingencies are further discussed in Notes 2, 3, 11 and 12 to the Consolidated Financial Statements, respectively.

Regulatory Balancing Accounts

During the rate freeze period, the difference between certain generation-related revenue and generation-related costs are being accumulated in the transition cost balancing account (TCBA). The gains resulting from the sale of 12 of SCE's generating plants during 1998 have been credited to the TCBA; the losses are being amortized over the remaining transition period and accumulated in the TCBA.

In June 2000, SCE credited the TCBA for the estimated excess of the market value over book value of its hydroelectric generation assets and simultaneously recorded the same amount in the generation asset balancing account (GABA), pursuant to a CPUC decision. This balance was to remain in GABA until final market valuation of the hydroelectric generation assets. If there was a difference in the final market valuation, it would have been credited to or recovered from customers through the TCBA mechanism. Due to the various unresolved regulatory and legislative issues (as discussed in Note 3), the GABA transaction was reclassified back into the TCBA as of December 31, 2000.

The coal and hydroelectric generation balancing accounts tracked the differences between market revenue from coal and hydroelectric generation and the plants' operating costs after April 1, 1998. Overcollections were credited to the TCBA in 1998 and 1999, pursuant to a 1997 CPUC decision. Due to a January 4, 2001, interim CPUC decision, the balance at year-end 2000 was not credited to the TCBA, pending further testimony and evidence on the implications of crediting the overcollections to the transition revenue account (TRA) rather than the TCBA. The TRA is a CPUC-authorized regulatory asset in which SCE recorded the difference between revenue received from customers through currently frozen rates and the costs of providing service to customers, including power procurement costs.

On March 27, 2001, the CPUC issued a decision stating, among other things, that the rate freeze had not ended, and the TCBA mechanism was to remain in place. However, the decision required SCE to recalculate the TCBA retroactive to January 1, 1998, the beginning of the rate freeze period. The new calculation required the coal and hydroelectric balancing accounting overcollections (which amounted to $1.5 billion as of December 31, 2000) to be closed monthly to the TRA, rather than annually to the TCBA. In addition, it required the TRA to be transferred to the TCBA on a monthly basis. Previous rules had called only for overcollections to be transferred to the TCBA monthly, while undercollections were to remain in the TRA until they were recovered from future overcollections or the end of the rate freeze, whichever came first. Based on the new rules, the $4.5 billion TRA undercollection as of December 31, 2000, and the coal and hydroelectric balancing account overcollections, were reclassified to the TCBA, and the TCBA balance was recalculated to be a $2.9 billion undercollection.

Due to the various unresolved regulatory and legislative issues (as discussed in Note 3), the TCBA undercollection was charged to earnings at December 31, 2000.

Balancing account undercollections and overcollections accrue interest. Income tax effects on all balancing account changes are deferred.

Regulatory Assets and Liabilities

In accordance with accounting principles for rate-regulated enterprises, SCE records regulatory assets, which represent probable future revenue associated with certain costs that will be recovered from customers through the rate-making process, and regulatory liabilities, which represent probable future reductions in revenue associated with amounts that are to be credited to customers through the rate-making process. SCE's discontinuance of the application of accounting principles for rate-regulated enterprises to its generation assets in 1997 did not result in a write-off of its generation-related regulatory assets at that time since the CPUC had approved recovery of these assets through the TCBA mechanism.

There are many factors that affect SCE's ability to recover its regulatory assets. SCE must assess the probability of recovery of its generation-related regulatory assets in light of the CPUC's March 27, 2001, and April 3, 2001, decisions (discussed in Note 3), including the retroactive transfer of balances from SCE's TRA to its TCBA and related changes. These decisions and other regulatory and legislative actions did not meet SCE's prior expectation that the CPUC would provide adequate cost recovery mechanisms. Until legislative and regulatory actions contemplated by the memorandum of understanding (MOU, as discussed in Note 3) occur, or other actions are taken, SCE is unable to conclude that its generation-related regulatory assets are probable of recovery through the rate-making process. Therefore, in accordance with accounting rules, SCE recorded a $2.5 billion after-tax charge to earnings as of December 31, 2000, to write off the TCBA and other regulatory assets (see below).

In addition to the TCBA, generation-related regulatory assets totaling $1.3 billion (including unamortized nuclear investment, flow-through taxes, unamortized loss on sale of plant, purchased-power settlements and other regulatory assets) were written off as of December 31, 2000. Unless the MOU is implemented or a rate-making mechanism is in place that would make recovery of SCE's TCBA-related regulatory assets probable, future net undercollections in the TCBA will be charged to earnings as losses are incurred.

Regulatory assets and liabilities included in the consolidated balance sheets are:

In millions December 31,	2000	1999
Generation-related:		
Unamortized nuclear investment — net	$ —	$1,366
Flow-through taxes	—	414
Unamortized loss on sale of plant	—	122
Purchased-power settlements	—	531
TCBA	—	1,044
Other — net	—	47
Subtotal	—	3,524
Rate reduction notes — transition cost deferral	**1,090**	707
Other:		
Flow-through taxes	**874**	859
Unamortized loss on reacquired debt	**273**	295
Environmental remediation	**52**	111
Regulatory balancing accounts and other	**(94)**	(42)
Subtotal	**1,105**	1,223
Total	**$2,195**	$5,454

The regulatory asset related to the rate reduction notes will be recovered over the terms of the rate reduction notes. The other regulatory assets and liabilities are being recovered through other components of the unbundled rates.

The unamortized nuclear investment regulatory asset was created during the second quarter of 1998. SCE reduced its remaining nuclear plant investment by $2.6 billion (as of June 30, 1998) and recorded a regulatory asset on its balance sheet for the same amount in accordance with asset impairment accounting standards. For this impairment assessment, the fair value of the investment was calculated by discounting expected future net cash flows. This reclassification had no effect on SCE's results of operations.

Nuclear

SCE has been recovering its investments in San Onofre Nuclear Generating Station Units 2 and 3 and Palo Verde Nuclear Generating Station on an accelerated basis, as authorized by the CPUC. The accelerated recovery was to continue through December 2001, earning a 7.35% fixed rate of return on investment. San Onofre's operating costs, including nuclear fuel and nuclear fuel financing costs, and incremental capital expenditures, are recovered through an incentive pricing plan which allows SCE to receive about 4¢ per kilowatt-hour through 2003. Any differences between these costs and the incentive price will flow through to the shareholders. Palo Verde's accelerated plant recovery, as well as operating costs, including nuclear fuel and nuclear fuel financing costs, and incremental capital expenditures, are subject to balancing account treatment through December 31, 2001. The San Onofre and Palo Verde rate recovery plans and the Palo Verde balancing account are part of the TCBA.

The nuclear rate-making plans and the TCBA mechanism will continue for rate-making purposes at least through the end of the rate freeze period and through 2001 for Palo Verde operating costs and through 2003 for the San Onofre incentive pricing plan. However, due to the various unresolved regulatory and legislative issues (as discussed in Note 3), SCE is no longer able to conclude that the unamortized nuclear investment is probable of recovery through the rate-making process. As a result, the balance was written off as a charge to earnings as of December 31, 2000.

The benefits of operation of the San Onofre units and the Palo Verde units are required to be shared equally with ratepayers beginning in 2004 and 2002, respectively. Palo Verde's existing nuclear unit incentive procedure will continue through 2001 only for purposes of calculating a reward for performance of any unit above an 80% capacity factor for a fuel cycle.

Under the MOU (discussed in Note 3), both nuclear facilities would be subject to cost-based ratemaking upon completion of their respective rate-making plans and the sharing mechanisms that were to begin in 2004 and 2002 would be eliminated.

Cash Equivalents

Cash equivalents include tax-exempt investments, time deposits and other investments with original maturities of three months or less.

Planned Major Maintenance

Certain plant facilities require major maintenance on a periodic basis. All such costs are expensed as incurred. Prior to January 1, 2000, EME recorded major maintenance costs on an accrue-in-advance method. EME voluntarily changed its accounting method for major maintenance to record such expenses as incurred due to guidance provided by the Securities and Exchange Commission. The cumulative effect of the change in accounting method was an $18 million after-tax benefit.

Fuel Inventory

SCE's inventory is valued under the last-in, first-out method for fuel oil and under the first-in, first-out method for coal. EME's fuel inventory is stated at the lower of weighted-average cost or market value.

Revenue

Electric utility revenue includes amounts for services rendered but unbilled at the end of each year. Some nonutility power generation revenue from power sales contracts is deferred and amortized to income over the life of the contracts.

Translation of Foreign Financial Statements

Assets and liabilities of most foreign operations are translated at end of period rates of exchange and the income statements are translated at the average rates of exchange for the year. Gains or losses from translation of foreign currency financial statements are included in comprehensive income in shareholders' equity. Gains or losses resulting from foreign currency transactions are included in other nonoperating income or deductions.

Investments

Net unrealized gains (losses) on equity investments are recorded as a separate component of shareholders' equity under the caption "Accumulated other comprehensive income." Unrealized gains and losses on decommissioning trust funds are recorded in the accumulated provision for decommissioning.

All investments are classified as available-for-sale.

Property and Plant

Utility plant additions, including replacements and betterments, are capitalized. Such costs include direct material and labor, construction overhead and an allowance for funds used during construction (AFUDC). AFUDC represents the estimated cost of debt and equity funds that finance utility-plant construction. AFUDC is capitalized during plant construction and reported in current earnings in other nonoperating income. 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.

AFUDC — equity was $11 million in 2000, $13 million in 1999 and $12 million in 1998. AFUDC — debt was $10 million in 2000, $11 million in 1999 and $8 million in 1998.

Replaced or retired property and removal costs less salvage are charged to the accumulated provision for depreciation. Depreciation expense stated as a percent of average original cost of depreciable utility plant was 3.6% for both 2000 and 1999, and 4.2% for 1998.

SCE's net investment in generation-related utility plant was $1.0 billion at both December 31, 2000, and December 31, 1999.

Nonutility property is capitalized at cost, including interest incurred on borrowed funds that finance construction. Depreciation of nonutility properties is primarily computed on a straight-line basis over their estimated useful lives. Depreciation expense stated as a percent of average original cost of depreciable nonutility property was, on a composite basis, 2.9% for 2000, 2.2% for 1999 and 3.6% for 1998.

Supplemental Cash Flows Information

Edison International's supplemental cash flows information was:

In millions Year ended December 31,	**2000**	1999	1998
Cash payments for interest and taxes:			
Interest — net of amounts capitalized	**$1,128**	$689	$474
Taxes	**3**	27	87
Non-cash investing and financing activities:			
Obligation to fund investments in partnerships and unconsolidated subsidiaries	**42**	278	7
Liabilities assumed (of companies acquired)	**397**	539	—

Related Party Transactions

Certain EME subsidiaries have ownership in partnerships that sell electricity generated by their project facilities to SCE under long-term power purchase agreements. Such sales to SCE were $716 million in 2000, $513 million in 1999 and $535 million in 1998. As a result of SCE's liquidity crisis, SCE has deferred payment for power purchases from some of these facilities.

Purchased Power — PX/ISO

Transactions through the PX and ISO (reported net) were:

In millions Year ended December 31,	**2000**	1999	1998
Purchases	**$8,449**	$2,490	$1,984
Generation sales	**6,120**	1,719	1,348
Purchased power — PX/ISO — net	**$2,329**	$ 771	$ 636

Other Nonoperating Income and Deductions

Other nonoperating income and deductions was comprised of:

In millions Year ended December 31,	**2000**	1999	1998
Nonutility nonoperating income	**$ 47**	$ 33	$ 11
Utility nonoperating income	**118**	162	129
Total other nonoperating income	**$165**	$195	$140
Nonutility nonoperating deductions	**$ 36**	$ 57	$ 37
Utility nonoperating deductions	**110**	107	117
Total other nonoperating deductions	**$146**	$164	$154

Derivative Financial Instruments

Edison International uses the hedge accounting method to record its nontrading derivative financial instruments. Hedge accounting requires an assessment that the transaction reduces risk, that the derivative be designated as a hedge at the inception of the derivative contract, and that the changes in the market value of a hedge move in an inverse direction to the item being hedged. Under hedge accounting, the derivative itself is not recorded on Edison International's balance sheet. Mark-to-market accounting would be used if the hedge accounting criteria were not met. Interest rate differentials and amortization of premiums for interest rate caps are recorded as adjustments to interest expense. If the derivatives were terminated before the maturity of the corresponding debt issuance, the realized gain or loss on the transaction would be amortized over the remaining term of the debt.

Edison International uses the fair value method for its trading and price risk management activities. Under this method, forwards, futures, options, swaps and other financial instruments with third parties are reflected at market value and are included in the balance sheet as assets or liabilities from trading and price risk management activities. In the absence of quoted values, financial instruments are valued at fair value, considering time value, volatility of the underlying commodity, and other factors as determined by Edison International. The resulting gains and losses are recognized in the profit and loss account in the period of change. Assets from trading and price risk management activities include the fair value of open financial positions related to trading activities and the present value of net amounts receivable from structured transactions. Liabilities from trading and price risk management activities include the fair value of open financial positions related to trading activities and the present value of net amounts payable from structured transactions.

Note 2. Liquidity Crisis

Edison International's liquidity is primarily affected by debt maturities, dividend payments, capital expenditures, investments in partnerships and unconsolidated subsidiaries, and SCE's power purchases. Capital resources include cash from operations and external financings.

The increasing undercollection in the TRA, coupled with SCE's anticipated near-term capital requirements and the adverse reaction of the credit markets to continued regulatory uncertainty regarding SCE's ability to recover its current and future power procurement costs, have materially and adversely affected SCE's and Edison International's liquidity. As a result of the liquidity crisis, SCE has taken and is taking steps to conserve cash, so that it can continue to provide service to its customers. As a part of this process, SCE has temporarily suspended payments of certain obligations for principal and interest on outstanding debt and for purchased power. As of March 31, 2001, SCE had $2.7 billion in obligations that were unpaid and overdue including: (1) $626 million to the PX or the ISO; (2) $1.1 billion to power producers that are qualifying facilities (QFs); (3) $229 million in PX energy credits for energy service providers; (4) $506 million of matured commercial paper; (5) $206 million of principal and interest on its 5⅞% notes; and (6) $7 million of other obligations. Unpaid obligations will continue to accrue interest, as applicable. At March 31, 2001, SCE has estimated cash reserves of approximately $2.0 billion, which is approximately $700 million less than its outstanding unpaid obligations and preferred stock dividends in arrears (see below).

SCE, Edison Capital and the parent company have drawn on their entire lines of credit, and only EME is able to obtain financing of any kind. To protect EME from the credit downgrade of Edison International and SCE and to help preserve the value of EME, EME has adopted certain amendments to its articles of incorporation and bylaws. As a result of investors' concerns regarding the California energy crisis and its impact on SCE's liquidity and overall financial condition, SCE has repurchased $549 million of pollution-control bonds that could not be remarketed in accordance with their terms. These bonds may be remarketed in the future if SCE's credit status improves sufficiently. In addition, Edison International, Edison Capital and SCE have been unable to market their commercial paper and other short-term financial instruments. As of March 31, 2001, SCE resumed payment of interest on its debt obligations. If the MOU is implemented, it is expected to allow SCE to recover its undercollected costs and to restore SCE's creditworthiness which would allow SCE to pay all of its past-due obligations.

On March 27, 2001, the CPUC ordered SCE to pay QFs for power deliveries on a going forward basis, commencing with April 2001 deliveries. SCE must pay QFs within 15 days of the end of the QF's billing period, and QFs are allowed to establish 15-day billing periods. Failure to make a payment when due will result in a fine equal to the amount owed. The CPUC also modified the formula used in calculating payments to QFs by substituting natural gas index prices based on deliveries at the Oregon border rather than the Arizona border. The CPUC stated that the changes will probably result in lower QF power prices. The changes apply to all QFs where appropriate, regardless of whether they use natural gas or other resources such as solar or wind.

On March 27, 2001, the CPUC also issued decisions on the California Procurement Adjustment (CPA) calculation and the approval of a 3¢ per kWh rate increase (see Note 3). Based on these two decisions, SCE estimates that revenue going forward will not be sufficient to recover retained generation, purchased-power and transition costs. In comments filed with the CPUC on March 29, 2001, and April 2, 2001, SCE provided a forecast showing that the net effects of the rate increase, the payment ordered to be made to the California Department of Water Resources (CDWR), and the QF decision discussed above could result in a shortfall to the CPA calculation of $1.7 billion for SCE during 2001. To implement the MOU, it will be necessary for the CPUC to modify or rescind these decisions.

In light of SCE's liquidity crisis, its Board of Directors did not declare quarterly common stock dividends to its parent, Edison International, in either December 2000 or March 2001. In addition, Edison International's Board of Directors did not declare a common stock dividend to its shareholders. Also, SCE's Board has not declared the regular quarterly dividends for SCE's cumulative preferred stock, 4.08% Series, 4.24% Series, 4.32% Series, 4.78% Series, 6.05% Series, 6.45% Series and 7.23% Series in 2001. The total preferred stock dividends in arrears is $6 million as of March 31, 2001. As a result of the $2.5 billion charge to earnings as of December 31, 2000, SCE's retained earnings are now in a deficit position and therefore, under California law, SCE will be unable to pay dividends as long as a deficit remains. SCE does not meet other tests under which dividends can be paid from sources other than retained earnings. As long as dividends in arrears on SCE's cumulative preferred stock remain unpaid, SCE cannot pay any dividends on its common stock.

In addition to the above, SCE has begun immediate cost-cutting measures which, together with previously announced actions, such as freezing new hires, postponing certain capital expenditures and ceasing new charitable contributions, are aimed at reducing general operating costs. SCE's current cost-cutting measures are intended to allow it to continue to operate while efforts to reach a regulatory solution, involving both state and federal authorities, are underway. Additional actions by SCE may be necessary if the energy and liquidity crisis is not resolved in the near future.

On April 9, 2001, SCE and the CDWR signed an MOU that, if approved by the legislature, would allow SCE to restore its financial health.

For a more detailed discussion on the matters discussed above, see Notes 3 through 7.

SCE's future liquidity depends, in large part, on whether the MOU is implemented, or other action by the California Legislature and the CPUC is taken in a manner sufficient to resolve the energy crisis and the cash flow deficit created by the current rate structure and the excessively high price of energy. Without a change in circumstances, such as that contemplated by the MOU, resolution of SCE's liquidity crisis and its ability to continue to operate outside of bankruptcy is uncertain.

The parent company and the nonutility affiliates believe that their corporate financing plans will be successful in meeting cash requirements in 2001.

Note 3. Electric Utility Regulatory Matters

Status of Transition and Power-Procurement Cost Recovery

SCE's transition costs include power purchases from QF contracts (which are the direct result of prior legislative and regulatory mandates), recovery of certain generating assets and regulatory commitments consisting of recovery of costs incurred to provide service to customers. Such commitments include the recovery of income tax benefits previously flowed through to customers, postretirement benefit transition costs, accelerated recovery of investment in San Onofre Units 2 and 3 and the Palo Verde units, and certain other costs. Transition costs related to power-purchase contracts are being recovered through the terms of each contract. Most of the remaining transition costs may be recovered through the end of the transition period (not later than March 31, 2002). Although the MOU provides for, among other things, SCE to be entitled to sufficient revenue to cover its costs from January 2001 associated with retained generation and existing power contracts, the implementation of the MOU requires the CPUC to modify various decisions. Until the various regulatory and legislative actions to implement the MOU are taken, or other actions occur that make such recovery probable, SCE is not able to conclude that the regulatory assets and liabilities related to purchased-power settlements, the unamortized loss on SCE's generating plant sales in 1998, and various other regulatory assets and liabilities (including income taxes previously flowed through to customers) related to certain generating assets are probable of recovery through the rate-making process. As a result, these balances were written off as a charge to earnings as of December 31, 2000.

During the rate freeze period, there are three sources of revenue available to SCE for transition cost recovery: revenue from the sale or valuation of generation assets in excess of book values, net market revenue from the sale of SCE-controlled generation into the ISO and PX markets and competition transition charge (CTC) revenue. However, due to events discussed elsewhere in this report, revenue from the sale or valuation of generation assets in excess of book values (state legislation enacted in January 2001 prohibits the sale of SCE's remaining generation assets until 2006) and from the sale of SCE-controlled generation into the ISO and PX markets is no longer available to SCE. During 1998, SCE sold all of its gas-fueled generation plants for $1.2 billion, over $500 million more than the combined book value. Net proceeds of the sales were used to reduce transition costs, which otherwise were expected to be collected through the TCBA mechanism.

Net market revenue from sales of power and capacity from SCE-controlled generation sources was also applied to transition cost recovery. Increases in market prices for electricity affected SCE in two fundamental ways prior to the CPUC's March 27, 2001, rate stabilization decision. First, CTC revenue decreased because there was less or no residual revenue from frozen rates due to higher cost PX and ISO power purchases. Second, transition costs decreased because there was increased net market revenue due to sales from SCE-controlled generation sources to the PX at higher prices (accumulated as an overcollection in the coal and hydroelectric balancing accounts). Although the second effect mitigated the first to some extent, the overall impact on transition cost recovery was negative because SCE purchased more power than it sold to the PX. In addition, higher market prices for electricity adversely affected SCE's ability to recover non-transition costs during the rate freeze period. Since May 2000, market prices for electricity were extremely high and there was insufficient revenue from customers under the frozen rates to cover all costs of providing service during that period, and therefore there was no positive residual CTC revenue transferred into the TCBA.

CTC revenue is determined residually (i.e., CTC revenue is the residual amount remaining from monthly gross customer revenue under the rate freeze after subtracting the revenue requirements for transmission, distribution, nuclear decommissioning and public benefit programs, and ISO payments and power purchases from the PX and ISO). The CTC applies to all customers who are using or begin using utility services on or after the CPUC's 1995 restructuring decision date. Residual CTC revenue is calculated through the TRA mechanism. Under CPUC decisions in existence prior to March 27, 2001, positive residual CTC revenue (TRA overcollections) was transferred to the TCBA monthly; TRA undercollections were to remain in the TRA until they were offset by overcollections, or the rate freeze ended, whichever came first. Pursuant to the March 27, 2001, rate stabilization decision, both positive and negative residual CTC revenue is transferred to the TCBA on a monthly basis, retroactive to January 1, 1998.

Upon recalculating the TCBA balance based on the new decision, SCE has received positive residual CTC revenue (TRA overcollections) of $4.7 billion to recover its transition costs from the beginning of the rate freeze (January 1, 1998) through April 2000. As a result of sustained higher market prices, SCE experienced the first month in which costs exceeded revenue in May 2000. Since then, SCE's costs to provide power have continued to exceed revenue from frozen rates and as a result, the cumulative positive residual CTC revenue flowing into the TCBA mechanism has been reduced from $4.7 billion to $1.4 billion as of December 31, 2000. The cumulative TCBA undercollection (as recalculated) is $2.9 billion as of December 31, 2000. A summary of the components of this cumulative undercollection is as follows:

In millions	
Transition costs recorded in the TCBA:	
QF and interutility costs	$3,561
Amortization of nuclear-related regulatory assets	3,090
Depreciation of plant assets	577
Other transition costs	634
Total transition costs	7,862
Revenue available to recover transition costs	(4,984)
Unrecovered transition costs	**$2,878**

Unless the regulatory and legislative actions required to implement the MOU, or other actions that make recovery probable are taken, SCE is not able to conclude that the recalculated TCBA net undercollection is probable of recovery through the rate-making process. As a result, the $2.9 billion TCBA net undercollection was written off as a charge to earnings as of December 31, 2000. In its interim rate stabilization decision of March 27, 2001, the CPUC denied a December motion by SCE to end the rate freeze, and stated that it will not end until recovery of all specified transition costs (including TCBA undercollections as recalculated) or March 31, 2002.

Rate Stabilization Proceeding

In January 2000, SCE filed an application with the CPUC proposing rates that would go into effect when the current rate freeze ends on March 31, 2002, or earlier, depending on the pace of transition cost recovery. On December 20, 2000, SCE filed an amended rate stabilization plan application, stating that the CPUC must recognize that the statutory rate freeze is now over in accordance with California law, and requesting the CPUC to approve an immediate 30% increase to be effective, subject to refund, January 4, 2001. SCE's plan included a trigger mechanism allowing for rate increases of 5% every six months if SCE's TRA undercollection balance exceeds $1 billion. Hearings were held in late December 2000.

On January 4, 2001, the CPUC issued an interim decision that authorized SCE to establish an interim surcharge of 1¢ per kWh for 90 days, subject to refund. The revenue from the surcharge is being tracked through a balancing account and applied to ongoing power procurement costs. The surcharge resulted in rate increases, on average, of approximately 7% to 25%, depending on the class of customer. As noted in the decision, the 90-day period allowed independent auditors engaged by the CPUC to perform a comprehensive review of SCE's financial position, as well as that of Edison International and other affiliates.

On January 29, 2001, independent auditors hired by the CPUC issued a report on the financial condition and solvency of SCE and its affiliates. The report confirmed what SCE had previously disclosed to the CPUC in public filings about SCE's financial condition. The audit report covers, among other things, cash needs, credit relationships, accounting mechanisms to track stranded cost recovery, the flow of funds between SCE and Edison International, and earnings of SCE's California affiliates. On April 3, 2001, the CPUC adopted an order instituting investigation (originally proposed on March 15, 2001). The order reopens the past CPUC decisions authorizing the utilities to form holding companies and initiates an investigation into: whether the holding companies violated company requirements to give priority to the capital needs of their respective utility subsidiaries; whether ring-fencing actions by Edison International and PG&E Corporation and their respective nonutility affiliates also violated the requirements to give priority to the capital needs of their utility subsidiaries; whether the payment of dividends by the utilities violated requirements that the utilities maintain dividend policies as though they were comparable stand-alone utility companies; any additional suspected violations of laws or CPUC rules and decisions; and whether additional rules, conditions, or other changes to the holding company decisions are necessary. An assigned commissioner's ruling on March 29, 2001, required Edison International and SCE to respond within 10 days to document requests and questions that are substantially identical to those included in the March 15 proposed order instituting investigation. The MOU calls for the CPUC to adopt a decision clarifying that the first priority condition in SCE's holding company decision refers to equity investment, not working capital for operating costs. Neither Edison International nor SCE can provide assurance that the CPUC will adopt such a decision, or predict what effects this investigation or any subsequent actions by the CPUC may have on either of them.

In its interim order adopted on March 27, 2001, the CPUC granted SCE a rate increase in the form of a 3¢ per kWh surcharge applied only to electric power costs, effective immediately, and affirmed that the 1¢ interim surcharge granted on January 4, 2001, is now permanent. Although the 3¢ increase was authorized immediately, the surcharge will not be collected in rates until the CPUC establishes an appropriate rate design, which is not expected to occur until May 2001. SCE has asked the CPUC to immediately adopt an interim rate increase that would allow the rate change to go into effect sooner. The CPUC also ordered that the 3¢ surcharge be added to the rate paid to the CDWR pursuant to the interim CDWR-related decision.

Also, in the interim order, the CPUC granted a petition previously filed by The Utility Reform Network and directed that the balance in SCE's TRA account, whether over- or undercollected, be transferred on a monthly basis to the TCBA account, retroactive to January 1, 1998. Previous rules called only for TRA overcollections (residual CTC revenue) to be transferred to the TCBA. The CPUC also ordered SCE to transfer the coal and hydroelectric balancing account overcollections to the TRA on a monthly basis before any transfer of residual CTC revenue to the TCBA, retroactive to January 1, 1998. Previous rules called for overcollections in these two balancing accounts to be transferred directly to the TCBA on an annual basis. SCE believes this interim order attempts to retroactively transform power purchase costs in the TRA into transition costs in the TCBA. However, the CPUC characterized the accounting changes as merely reducing the prior residual CTC revenue recorded in the TCBA, thereby only affecting the amount of transition cost recovery achieved to date. Based upon the transfer of balances into the TCBA, the CPUC denied SCE's December 2000 filing to have the current rate freeze end, and stated that it will not end until recovery of all specified transition costs or March 31, 2002; and that balances in the TRA cannot be recovered after the end of the rate freeze. The CPUC also said that it will monitor the balances remaining in the TCBA and consider how to address remaining balances in the ongoing proceedings. If the CPUC does not modify this decision in a manner consistent with the MOU, SCE intends to challenge this decision through all appropriate means.

Although the CPUC has authorized a substantial rate increase in its March 27, 2001, order, it has allocated the revenue from the increase entirely to future purchased-power costs without addressing SCE's past undercollections for the costs of purchased power. The CPUC's decisions do not assure that SCE will be able to meet its ongoing obligations or repay past due obligations. By ordering immediate payments to the CDWR and QFs, the CPUC aggravated SCE's cash flow and liquidity problems. Additionally, the CPUC expressed the view that AB 1X (see CDWR Power Purchases) continues the utilities' obligations to serve their customers, and stated that it cannot assume that the CDWR will purchase all the electricity needed above what the utilities either generate or have under contract (the net short position) and cannot order the CDWR to do so. This could result in additional purchased power costs with no allowed means of recovery. To implement the MOU, it will be necessary for the CPUC to modify or rescind these decisions. SCE cannot provide any assurance that the CPUC will do so.

Wholesale Electricity Markets

In October 2000, SCE filed a joint petition urging the FERC to immediately find the California wholesale electricity market to be not workably competitive, immediately impose a cap on the price for energy and ancillary services, and institute further expedited proceedings regarding the market failure, mitigation of market power, structural solutions and responsibility for refunds. On December 15, 2000, the FERC released a final order containing remedies and other actions in response to the problems in the California electricity market. The order, among other things, eliminated the requirement for California utilities to buy and sell power exclusively through the ISO and PX; created a benchmark price for wholesale bilateral power contracts; created penalties for under-scheduling power loads; provided for an independent governing board for the ISO; and established a breakpoint of $150/MWh so that bids below $150 may clear at a single market-clearing price at or below $150/MWh and bids above $150 will be paid as bid. On December 18, 2000, SCE filed with the FERC an emergency request for rehearing and expedited action seeking reconsideration of the December 15 order. On January 12, 2001, the FERC issued an order granting rehearing for the purpose of further consideration. The PX did not immediately implement the $150/MWh breakpoint and on February 26, 2001, made a compliance filing with the FERC, which requested the FERC's guidance on an acceptable recalculation methodology. On April 6, 2001, the FERC issued an order providing guidance to the PX, which should reduce SCE's energy costs owed to the PX for the month of January 2001.

On December 13, 2000, the ISO announced that generators of electricity were refusing to sell into the California market due to concerns about the financial stability of SCE and Pacific Gas and Electric Company. In response to this announcement, on December 14, 2000, the United States Secretary of Energy issued an order requiring power companies to make arrangements to generate and deliver electricity as requested by the ISO after the ISO certifies that it has been unable to acquire adequate supplies of electricity in the market. After being renewed multiple times, the order expired on February 6, 2001. However, on February 7, 2001, a federal court judge issued a temporary restraining order requiring power suppliers to sell to the California grid. On March 21, 2001, a federal court judge ordered one of the power suppliers to continue to sell power to the California grid. The three other power suppliers have signed an agreement with the judge voluntarily agreeing to continue to sell power to the grid while awaiting a review of the issue by the FERC. On April 6, 2001, the United States Court of Appeals issued a stay order, suspending the lower court's March 21 order until a final appeals ruling can be issued.

On December 26, 2000, SCE filed an emergency petition in the federal Court of Appeals challenging the FERC order and seeking a writ of mandamus requiring the FERC to immediately establish cost-based wholesale rates. On January 5, 2001, the court denied SCE's petition. The effect of the denial is to leave in place the FERC's market controls that have allowed wholesale prices to climb to current levels. SCE's petition for rehearing remains pending. SCE cannot predict what action the FERC may take. SCE is considering the possibility of judicial appeals and other actions.

On March 9, 2001, FERC directed 13 wholesale sellers of energy to refund $69 million or submit cost-of-service information to FERC to justify their prices above $273/MWh during ISO Stage 3 emergencies in January 2001. SCE will oppose the order as inadequate, particularly because the FERC is unwilling to exercise any control over sellers' exercise of market power during periods other than Stage 3 emergencies. On March 16, 2001, the FERC ordered six wholesale sellers of energy to refund an additional $55 million or submit cost-of-service information to the FERC to justify their prices above $430/MWh during ISO Stage 3 emergencies in February 2001. A Stage 3 emergency refers to 1.5% or less in reserve power, which could trigger rotating blackouts in some neighborhoods.

Memorandum of Understanding with the CDWR

On April 9, 2001, Edison International and SCE signed an MOU with the CDWR regarding the California energy crisis and its effects on SCE. The Governor of California and his representatives participated in the negotiation of the MOU, and the Governor endorsed implementation of all the elements of the MOU. The MOU sets forth a comprehensive plan calling for legislation, regulatory action and definitive agreements to resolve important aspects of the energy crisis, and which, if implemented, is expected to help restore SCE's creditworthiness and liquidity. Key elements of the MOU include:

- SCE will sell its transmission assets to the CDWR, or another authorized California state agency, at a price equal to 2.3 times their aggregate book value, or approximately $2.76 billion. If a sale of the transmission assets is not completed under certain circumstances, SCE's hydroelectric assets and other rights may be sold to the state in their place. SCE will use the proceeds of the sale in excess of book value to reduce its undercollected costs and retire outstanding debt incurred in financing those costs. SCE will agree to operate and maintain the transmission assets for at least three years, for a fee to be negotiated.
- Two dedicated rate components will be established to assist SCE in recovering the net undercollected amount of its power procurement costs through January 31, 2001, estimated to be approximately $3.5 billion. The first dedicated rate component will be used to securitize the excess of the undercollected amount over the expected gain on sale of SCE's transmission assets, as well as certain other costs. Such securitization will occur as soon as reasonably practicable after passage of the necessary legislation and satisfaction of other conditions of the MOU. The second dedicated rate component would not be securitized and would not appear in rates unless the transmission sale failed to close within a two-year period. The second component is designed to allow SCE to obtain bridge financing of the portion of the undercollection intended to be recovered through the gain on the transmission sale.
- SCE will continue to own its generation assets, which will be subject to cost-based ratemaking, through 2010. SCE will be entitled to collect revenue sufficient to cover its costs from January 1, 2001, associated with the retained generation assets and existing power contracts. The MOU calls for the CPUC to adopt cost recovery mechanisms consistent with SCE obtaining and maintaining an investment grade credit rating.
- The CDWR will assume the entire responsibility for procuring the electricity needs of retail customers within SCE's service territory through December 31, 2002, to the extent that those needs are not met by generation sources owned by or under contract to SCE. (The unmet needs are referred to as SCE's net short position.) SCE will resume procurement of its net short position after 2002. The MOU calls for the CPUC to adopt cost recovery mechanisms to make it financially practicable for SCE to reassume this responsibility.
- SCE's authorized return on equity will not be reduced below its current level of 11.6% before December 31, 2010. Through the same date, a rate-making capital structure for SCE will not be established with different proportions of common equity or preferred equity to debt than set forth in current authorizations. These measures are intended to enable SCE to achieve and maintain an investment-grade credit rating.
- Edison International and SCE will commit to make capital investments in SCE's regulated businesses of at least $3 billion through 2006, or a lesser amount approved by the CPUC. The

equity component of the investments will be funded from SCE's retained earnings or, if necessary, from equity investments by Edison International.

- EME will execute a contract with the CDWR or another state agency for the provision of power to the state at cost-based rates for ten years from a power project currently under development. EME will use all commercially reasonable efforts to place the first phase of the project into service before the end of summer 2001.
- SCE will grant perpetual conservation easements over approximately 21,000 acres of lands associated with SCE's Big Creek and Eastern Sierra hydroelectric facilities. The easements initially will be held by a trust for the benefit of the State of California, but ultimately may be assigned to nonprofit entities or certain governmental agencies. SCE will be permitted to continue utility uses of the subject lands.
- After the other elements of the MOU are implemented, SCE will enter into a settlement of or dismiss its federal district court lawsuit against the CPUC seeking recovery of past undercollected costs. The settlement or dismissal will include related claims against the State of California or any of its agencies, or against the federal government.

The sale of SCE's transmission system and other elements of the MOU must be approved by the FERC. Edison International, SCE and the CDWR committed in the MOU to proceed in good faith to sponsor and support the required legislation and to negotiate in good faith the necessary definitive agreements. The MOU may be terminated by either SCE or the CDWR if required legislation is not adopted and definitive agreements executed by August 15, 2001, or if the CPUC does not adopt required implementing decisions within 60 days after the MOU was signed, or if certain other adverse changes occur. Edison International and SCE cannot provide assurance that all the required legislation will be enacted, regulatory actions taken, and definitive agreements executed before the applicable deadlines.

CDWR Power Purchases

Pursuant to an emergency order signed by the Governor, the CDWR began making emergency power purchases for SCE's customers on January 18, 2001. On February 1, 2001, Assembly Bill 1 (First Extraordinary Session) (AB 1X) was enacted into law. The new law authorized the CDWR to enter into contracts to purchase electric power and sell power at cost directly to retail customers being served by SCE, and authorized the CDWR to issue revenue bonds to finance electricity purchases. The new law directed the CPUC to determine the amount of the CPA as a residual amount of SCE's generation-related revenue, after deducting the cost of SCE-owned generation, QF contracts, existing bilateral contracts and ancillary services. The new law also directed the CPUC to determine the amount of the CPA that is allocable to the power sold by the CDWR, which will be payable to the CDWR when received by SCE. On March 7, 2001, the CPUC issued an interim order in which it held that the CDWR's purchases are not subject to prudency review by the CPUC, and that the CPUC must approve and impose, either as a part of existing rates or as additional rates, rates sufficient to enable the CDWR to recover its revenue requirements.

On March 27, 2001, the CPUC issued an interim CDWR-related order requiring SCE to pay the CDWR a per-kWh price equal to the applicable generation-related retail rate per kWh for electricity (based on rates in effect on January 5, 2001), for each kWh the CDWR sells to SCE's customers. The CPUC determined that the generation-related retail rate should be equal to the total bundled electric rate (including the 1¢ per kWh temporary surcharge adopted by the CPUC on January 4, 2001) less certain nongeneration-related rates or charges. For the period January 19 through January 31, 2001, the CPUC ordered SCE to pay the CDWR at a rate of 6.277¢ per kWh for power delivered on an interim basis to SCE's customers. The CPUC determined that the applicable rate component is 7.277¢ per kWh (which will increase to 10.277¢ per kWh for electricity delivered after March 27, 2001, due to the 3¢ surcharge discussed in Rate Stabilization Proceeding), for electricity delivered by the CDWR to SCE's retail customers after February 1, 2001, until more specific rates are calculated. The CPUC ordered SCE to pay the CDWR within 45 days after the CDWR supplies power to retail customers, subject to penalties for each day the payment is late. Using these rates, SCE has billed customers $196 million for energy sales made by the CDWR during the period January 19 through March 31, 2001, and has forwarded $52 million to the CDWR on behalf of these customers as of March 31, 2001.

On April 3, 2001, the CPUC adopted the method (originally proposed in the March 27 CDWR-related order discussed above) it will use to calculate the CPA (which was established by AB 1X) and then applied the method to calculate a company-wide CPA rate for SCE. The CPUC used that rate to determine the CPA revenue amount that can be used by the CDWR for issuing bonds. The CPUC stated that its decision is narrowly focused to calculate the maximum amount of bonds that the CDWR may issue and does not dedicate any particular revenue stream to the CDWR. The CPUC determined that SCE's CPA rate is 1.120¢ per kWh, which generates annual revenue of $856 million. In its calculation of the CPA, the CPUC disregarded all of the adjustments requested by SCE in its comments filed on March 29 and April 2, 2001. SCE's comments included, among other things, a forecast showing that the net effect of the rate increases (discussed in Rate Stabilization Proceeding), as well as the March 27 QF payment decision (discussed in Note 2) and the payments ordered to be made to CDWR, could result in a shortfall in the CPA calculation of $1.7 billion for SCE during 2001. SCE estimates that its future revenue will not be sufficient to cover its retained generation, purchased-power and transition costs. To implement the MOU, the CPUC will need to modify the calculation methods and provide reasonable assurance that SCE will be able to recover its ongoing costs.

SCE believes that the intent of AB 1X was for the CDWR to assume full responsibility for purchasing all power needed to serve the retail customers of electric utilities, in excess of the output of generating plants owned by the electric utilities and power delivered to the utilities under existing contracts. However, the CDWR has stated that it is only purchasing power that it considers to be reasonably priced, leaving the ISO to purchase in the short-term market the additional power necessary to meet system requirements. The ISO, in turn, takes the position that it will charge SCE for the costs of power it purchases in this manner. If SCE is found responsible for any portion of the ISO's purchases of power for resale to SCE's customers, SCE will continue to incur purchased-power costs in addition to the unpaid costs described above. In its March 27, 2001, interim order, the CPUC stated that it cannot assume that the CDWR will pay for the ISO purchases and that it does not have the authority to order the CDWR to do so. Litigation among certain power generators, the ISO and the CDWR (to which SCE is not a party), and proceedings before the FERC (to which SCE is a party), may result in rulings clarifying the CDWR's financial responsibility for purchases of power. On April 6, 2001, the FERC issued an order confirming that the ISO must have a creditworthy buyer for any transaction. In any event, SCE takes the position that it is not responsible for purchases of power by the CDWR or the ISO on or after January 18, 2001, the day after the Governor signed the order authorizing the CDWR to begin purchasing power for utility customers. SCE cannot predict the outcome of any of these proceedings or issues. The recently executed MOU states that the CDWR will assume the entire responsibility for procuring the electricity needs of retail customers within SCE's service territory through December 31, 2002, to the extent those needs are not met by generation sources owned by or under contract to SCE (SCE's net short position). SCE will resume buying power for its net short position after 2002. The MOU calls for the CPUC to adopt cost-recovery mechanisms to make it financially practicable for SCE to reassume this responsibility.

Hydroelectric Market Value Filing

In 1999, SCE filed an application with the CPUC establishing a market value for its hydroelectric generation-related assets at approximately $1.0 billion (almost twice the assets' book value) and proposing to retain and operate the hydroelectric assets under a performance-based, revenue-sharing mechanism. If approved by the CPUC, SCE would be allowed to recover an authorized, inflation-indexed operations and maintenance allowance, as well as a reasonable return on capital investment. A revenue-sharing arrangement would be activated if revenue from the sale of hydroelectricity exceeds or falls short of the authorized revenue requirement. SCE would then refund 90% of the excess revenue to ratepayers or recover 90% of any shortfall from ratepayers. If the MOU is implemented, SCE's hydroelectric assets will be retained through 2010 under cost-based rates, or they may be sold to the state if a sale of SCE's transmission assets is not completed under certain circumstances.

Note 4. Financial Instruments

Edison International's risk management policy allows the use of derivative financial instruments to manage financial exposure on its investments and fluctuations in interest rates, foreign currency exchange rates and oil, gas and energy prices but prohibits the use of these instruments for speculative or trading purposes, except at EME's trading operations unit (acquired in September 2000).

SCE used the mark-to-market accounting method for its gas call options, which were used to mitigate SCE's transition cost recovery exposure to increases in energy prices. Gains and losses from monthly changes in market prices were recorded as income or expense. In addition, the options' costs and market price changes were included in the TCBA. As a result, the mark-to-market gains or losses had no effect on earnings. In October 2000, SCE sold its gas call options resulting in a $190 million gain. The options covered various periods through 2001. The gains were credited to the TCBA.

The PX block forward market allowed SCE to purchase monthly blocks of energy and ancillary services for six days a week (excluding Sundays and holidays) for 8 hours to 16 hours a day, up to 12 months in advance of the delivery date.

SCE purchased block forward energy contracts through the PX, with various terms and prices, to hedge its exposure to fluctuations in energy prices. Due to downgrades in SCE's credit ratings and SCE's failure to pay its obligations to the PX, the PX suspended SCE's market trading privileges and sought to liquidate SCE's block forward contracts. On February 2, 2001, SCE's motion for a preliminary injunction was denied, freeing the PX to liquidate the contracts and apply the proceeds to amounts owed by SCE to the PX. On the same day, the State seized the contracts for the benefit of the State before they could be sold by the PX. The State must compensate SCE for the reasonable value of the contracts. The PX has indicated that it will also seek to recover the monies that SCE owes to the PX from any proceeds realized from those contracts. After other elements of the MOU are implemented, SCE would relinquish all claims against the State for seizing these contracts. At December 31, 2000, these contracts had a nominal value of $234 million.

SCE also has bilateral forward contracts, which are considered normal purchases under accounting rules. At December 31, 2000, these contracts had a nominal value of $798 million. Due to its deteriorating credit ratings, SCE has been unable to purchase additional bilateral forward contracts, and $379 million (nominal value) of its existing contracts were terminated by the counterparties in early 2001. SCE is exposed to credit loss in the event of nonperformance by the counterparties to its bilateral forward contracts, but does not expect the counterparties to fail to meet their obligations. The counterparties are required to post collateral depending on the creditworthiness of each counterparty. SCE is exposed to market risk resulting from changes in the spot market price for power. Changes in the value of bilateral forward contracts affects purchased power expense in the period when the power is delivered.

SCE used an interest rate swap to reduce the potential impact of interest rate fluctuations on floating-rate long-term debt. At December 31, 2000, and December 31, 1999, SCE had an interest rate swap agreement which fixed the interest rate at 5.585% for $196 million of debt due 2008; the receive rate on the swap averaged 3.839% in 2000. As a result of the downgrade in SCE's credit rating below the level allowed under the interest rate hedge agreement, on January 5, 2001, the counterparty on this interest rate swap terminated the agreement. As a result of the termination of the swap, SCE is paying a floating rate on $196 million of its debt due 2008. The realized loss of $26 million will be amortized over a period ending in 2008.

EME uses foreign currency forward exchange contracts and interest rate swaps to mitigate the risk of fluctuations in foreign currency exchange rates and interest rates. The maturity date of the swaps generally occur prior to the final maturity of the underlying debt. Under the fixed to variable swap agreements, the fixed interest rate payments are at a weighted-average rate of 5.65% at December 31, 2000, and 1999. Variable rate payments are based on six-month LIBOR capped at 9%. The weighted-average LIBOR rate applicable to these agreements was 5.605% and 6.22% at December 31, 2000, and 1999, respectively. Under the variable to fixed swap agreements, EME paid counterparties interest at a weighted-average fixed rate of 7.59% and 7.6% at December 31, 2000, and 1999, respectively. Counterparties paid EME interest at a weighted-average variable rate of 6.43% and 5.03% at December 31, 2000, and 1999, respectively. The weighted-average variable interest rates are based on LIBOR or equivalent interest rate benchmarks for foreign-denominated interest rate swap agreements.

EME enters into electricity rate swap agreements to manage its exposure to the United Kingdom and Australia market (pool) price volatilities. The related price differentials to be paid or received are currently recorded as adjustments to electric revenue or fuel expense. Projects in the United Kingdom currently sell their electrical energy and capacity through a centralized electricity pool, which establishes a half-hourly clearing price, or pool price, for electrical energy. The pool price is extremely volatile and can vary by a factor of 10 or more over the course of a few hours due to large differentials in demand according to the time of day. The pricing arrangements include provision for capacity payments to be added to the basic pool price at time of capacity shortage. First Hydro, Ferrybridge and Fiddler's Ferry mitigate a significant portion of the market risk of the pool by entering into electricity rate swap agreements, related to either the selling or purchasing price of power. These contracts are sold in various structures and act as a means of stabilizing production revenue or purchasing costs by removing an element of net exposure to pool price volatility.

Electric power at EME's Homer City plant is sold under bilateral arrangements with domestic utilities and power marketers under short-term contracts (two years or less) or to the Pennsylvania-New Jersey-Maryland Power Pool (PJM) or the New York Independent System Operator (NYISO). These pools have short-term markets which establish an hourly clearing price. Homer City is located in the PJM control area and is physically connected to high-voltage transmission lines serving both the PJM and the NYISO markets. Power can also be transmitted to the mid-western United States. EME has developed risk management policies and procedures which, among other matters, address credit risk. It is EME's policy to sell to investment grade counterparties or counterparties that provide equivalent credit support. Exception to the policy is granted only after thorough review and scrutiny by EME's Risk Management Committee. Entities which have received exceptions are organized power pools and quasi-governmental agencies. EME intends on hedging a portion of the electric output of its merchant plants in order to lock in desirable outcomes. EME plans to manage the margin that is spread between electric prices and fuel prices when deemed appropriate. EME plans to use forward contracts, swaps, futures or option contracts to achieve those objectives.

Loy Yang B (EME's energy project in Australia) sells its electrical energy through a centralized electricity pool, which provides for a system of generator bidding, central dispatch and a settlement system based on a clearing market for each half-hour of every day. To mitigate the exposure to price volatility of the electricity traded in the pool, Loy Yang B has entered into a number of financial hedges. Between May 1997 and December 2000, 53% to 64% of the plant output sold was hedged under vesting contracts, with the remainder of the plant capacity hedged under the State hedge described below. Vesting contracts were put into place by the State Government of Victoria, Australia, between each generator and each distributor, prior to the privatization of electric power distributors in order to provide more predictable pricing for those electricity customers that were unable to choose their electricity retailer. Vesting contracts set base strike prices at which the electricity will be traded, and the parties to the agreement make payments, calculated based on the difference between the price in the contract and the half-hourly pool clearing price for the element of power under the contract. Vesting contracts were sold in various structures and accounted for as electricity rate swap agreements. The State hedge with the State Electricity Commission of Victoria is a long-term contractual agreement based upon a fixed price commencing in May 1997 and terminating in October 2016. The State government guarantees the State Electricity Commission of Victoria's obligations under the State hedge. From January 2001 to July 2014, approximately 77% of the plant output sold is hedged under the State hedge. From August 2014 to October 2016, approximately 56% of the plant output is hedged under the State hedge. Additionally, Loy Yang B entered into a number of fixed forward electricity contracts effective January 2001, which will expire either January 1, 2002, or January 1, 2003, and which will further mitigate against the price volatility of the electricity pool.

Edison International is subject to concentrations of credit risk as the result of elements involved in EME's financial instruments and power-sales contracts. Credit risk relates to the risk of loss that EME would incur as a result of nonperformance by counterparties (major financial institutions and domestic foreign utilities) under their contractual obligations. One of EME's customers, Exelon Generation, accounted for 33% of EME's revenue during 2000. Any failure by Exelon Generation to make payments under the power purchase agreements could adversely affect EME's results of operations. EME attempts to mitigate credit risk by contracting with counterparties that have a strong capacity to meet their contractual obligations and by monitoring their credit quality. In addition, EME seeks to secure long-term power-sales contracts for its investments in domestic operating projects that are expected to result in adequate cash flow under a wide range of economic and operating circumstances. To accomplish this, EME attempts to structure its long-term contracts so that fluctuations in fuel costs will produce similar fluctuations in electric and/or steam revenue by entering into long-term fuel supply and transportation agreements. Accordingly, EME does not anticipate a material effect on its results of operations or financial condition as a result of counterparty nonperformance.

Edison Capital has entered into foreign currency contracts to reduce the potential impact of changes in foreign exchange rates and future foreign currency denominated cash flows, and into interest rate swaps to reduce the potential impact of changes in interest rates. In 2000, Edison Capital made payments and received payments on its swap agreements. The net effective interest rate of these transactions results in Edison Capital paying a weighted average fixed rate of 6.156% and receiving a weighted average fixed rate of 6.719%. In 1999, Edison Capital made payments on its swap agreements on which the net effective weighted average interest rate was 5.520%. There were no payments received on the swap agreements in 1999.

Edison International had the following interest rate, foreign currency and commodity hedges:

In millions December 31,	**2000**		1999	
	Notional Amount	**Contract Expires**	Notional Amount	Contract Expires
Interest rate swaps:				
Fixed to variable	**$ 100**	**2002**	$ 100	2002
Variable to fixed	**1,246**	**2001-2009**	2,148	2000-2009
Interest rate caps	**584**	**2005-2010**	626	2005
Foreign currency contracts	**111**	**2001-2002**	9	2001
Derivative commodity contracts:				
Forwards	**489**	**2001-2003**	—	—
Futures	**(70)**	**2001**	—	—
Options	**4**	**2001**	47	2001
Swaps	**1,748**	**2001-2016**	1,803	2000-2016

On January 1, 2001, Edison International adopted a new accounting standard for derivative instruments and hedging activities. The new standard requires all derivatives to be recognized on the balance sheet at fair value. Gains or losses from changes in fair value would be recognized in earnings in the period of change unless the derivative is designated as a hedging instrument. Gains or losses from hedges of a forecasted transaction or foreign currency exposure would be recorded as a separate component of shareholders' equity under the caption "Accumulated other comprehensive income." Gains or losses from hedges of a recognized asset or liability or a firm commitment would be reflected in earnings for the ineffective portion of the hedge. SCE's derivatives qualify for hedge accounting under the new standard. SCE does not anticipate any earnings impact from its derivatives, since it expects that any market price changes will be recovered in rates. As a result of the adoption of the new standard, Edison International expects that the quarterly earnings from its EME subsidiary will be more volatile than earnings reported under the prior accounting policy. For Edison International's 2001 earnings, the cumulative effect on prior years resulting from adoption of the new standard is expected to be less than $10 million.

Fair values of financial instruments were:

In millions December 31,	**2000**		1999	
	Cost Basis	**Fair Value**	Cost Basis	Fair Value
Financial assets:				
Decommissioning trusts	**$ 1,720**	**$ 2,505**	$ 1,650	$ 2,509
Equity investments	**—**	**—**	—	33
Gas call options	**—**	**—**	28	20
Electricity rate swaps	**—**	**555**	—	71
Power options	**2**	**2**	4	4
Forward power contracts/futures	**—**	**27**	—	—
Gas swaps	**—**	**7**	—	—
Financial liabilities:				
DOE decommissioning and decontamination fees	**$ 36**	**$ 31**	$ 40	$ 35
Interest rate hedges	**—**	**63**	—	44
Long-term debt	**12,150**	**11,197**	13,391	13,281
Utility preferred stock subject to mandatory redemption	**256**	**157**	256	259
Other preferred securities subject to mandatory redemption	**327**	**327**	359	360
Forward power contracts/futures	**—**	**143**	—	—
Gas swaps/futures	**50**	**56**	—	—
Power swaps	**—**	**1**	—	—
Emission options	**2**	**—**	—	—

Financial assets are carried at their fair value based on quoted market prices for decommissioning trusts, equity investments and gas call options and on financial models for electricity rate swaps. The fair value of the commodity contracts considers quoted market prices, time value, volatility of the underlying commodities and other factors.

Financial liabilities are recorded at cost. Financial liabilities' fair values are based on: discounted future cash flows for U.S. Department of Energy (DOE) decommissioning and decontamination fees; quoted market prices for the interest rate hedges; and brokers' quotes for long-term debt and preferred stock. Due to their short maturities, amounts reported for cash equivalents and short-term debt approximated fair value at December 31, 2000, and 1999.

As a result of investors' concerns regarding SCE and Edison International's liquidity difficulties, Edison International's short-term debt and long-term debt fair values have decreased approximately $250 million and $540 million, respectively, from amounts reported at year-end.

Gross unrealized holding gains on debt and equity securities were:

In millions December 31,	**2000**	1999
Decommissioning trusts:		
Municipal bonds	**$193**	$239
Stocks	**384**	454
U.S. government issues	**136**	119
Short-term and other	**72**	47
	785	859
Equity investments	**—**	33
Total	**$785**	$892

There were no unrealized holding losses on debt and equity securities for the years presented.

Commodity Derivatives — Trading

In September 2000, EME acquired the trading operations of Citizens Power LLC, expanding EME's trading operations beyond the traditional marketing of electric power. Energy trading and price risk management activities give rise to market risk (potential loss that can be caused by a change in the market value of a particular commitment). Market risks are actively monitored to ensure compliance with EME's risk management policies. EME performs a value at risk analysis daily to monitor its overall market risk exposure. This analysis measures the worst expected loss over a given time interval, under normal market conditions, at a given confidence level. Given the inherent limitations of value at risk and relying on a single risk measurement tool, EME supplements this approach with other techniques, including the use of stress testing and worst-case scenario analysis, as well as stop limits and counterparty credit exposure limits.

The fair value of the financial instruments, including forwards, options and swaps, related to trading and price risk management activities as of December 31, 2000, which include energy commodities, and the average fair value of those instruments held during the period from inception (September 1, 2000) to December 31, 2000, were:

In millions	**Fair Value at December 31, 2000**		**Average Fair Value for the Period Ended December 31, 2000**	
	Assets	**Liabilities**	**Assets**	**Liabilities**
Forward contracts	**$302**	**$282**	**$154**	**$147**
Option contracts	**1**	**4**	**3**	**2**
Swap agreements	**3**	**4**	**2**	**2**
Total	**$306**	**$290**	**$159**	**$151**

A portion of these assets and liabilities are classified as long-term in the balance sheet.

The approximate gross contract or notional amounts of the financial instruments as of December 31, 2000, were as follows:

In millions December 31, 2000	**Assets**	**Liabilities**
Forward contracts	**$433**	**$420**
Option contracts	**2**	**—**
Swap agreements	**40**	**64**

The net realized and change in unrealized gains or losses arising from trading and activities for the period from inception to December 31, 2000, are as follows:

In millions	Period Ended December 31,	**2000**
Forward contracts		**$68**
Option contracts		**(1)**
Swap agreements		**(5)**
Total		**$62**

The change in unrealized gains from trading and price risk management activities included in the above amounts was $12 million for the period ended December 31, 2000.

Note 5. Long-Term Debt

California law prohibits SCE from incurring or guaranteeing debt for its nonutility affiliates.

Almost all SCE properties are subject to a trust indenture lien. SCE has pledged first and refunding mortgage bonds as security for borrowed funds obtained from pollution-control bonds issued by government agencies. SCE uses these proceeds to finance construction of pollution-control facilities. Bondholders have limited discretion in redeeming certain pollution-control bonds, and SCE has arrangements with securities dealers to remarket or purchase them if necessary. As a result of investors' concerns regarding SCE's liquidity difficulties and overall financial condition, SCE had to repurchase $549 million of pollution control bonds in December 2000 and early 2001 that could not be remarketed in accordance with their terms.

Debt premium, discount and issuance expenses are amortized over the life of each 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.

Commercial paper intended to be refinanced for a period exceeding one year and used to finance nuclear fuel scheduled for use more than one year after the balance sheet date is classified as long-term debt.

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 non-bypassable residential and small commercial customer rates which constitute the transition property purchased by SCE Funding LLC. The notes are secured by the transition property and are not secured 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, 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. Due to SCE's recent credit downgrade, in January 2001, SCE began remitting its customer collections related to the rate-reduction notes on a daily basis.

Long-term debt consisted of:

In millions December 31,	2000	1999
First and refunding mortgage bonds:		
2002-2026 (5.625% to 7.25%)	**$ 1,175**	$ 1,400
Rate reduction notes:		
2001-2007 (6.17% to 6.42%)	**1,724**	1,970
Pollution-control bonds:		
2008-2040 (5.125% to 7.2% and variable)	**1,216**	1,196
Bonds repurchased	**(420)**	—
Funds held by trustees	**(20)**	(2)
Debentures and notes:		
2001-2029 (5.875% to 11.2% and variable)	**10,594**	9,633
Subordinated debentures:		
2044 (8.375%)	**100**	100
Commercial paper for nuclear fuel	**79**	71
Capital lease obligation	**1**	23
Current portion of capital lease obligation	**(1)**	(22)
Long-term debt due within one year	**(2,259)**	(940)
Unamortized debt discount — net	**(39)**	(38)
Total	**$12,150**	$13,391

Long-term debt maturities and sinking-fund requirements for the next five years are: 2001 — $2.3 billion; 2002 — $1.1 billion; 2003 — $1.7 billion; 2004 — $1.8 billion; and 2005 — $499 million.

As a result of its liquidity crisis, SCE has taken steps to conserve cash, and has been forced to consider further alternatives for conserving cash, so that it can continue to provide service to its customers. As a part of this process, SCE has temporarily suspended payments of certain obligations. As of March 31, 2001, SCE has failed to pay $206 million of maturing principal and accrued interest on its 5⅞% notes. Under the indenture for SCE's senior unsecured notes, the failure to pay principal was an immediate event of default as to the one series of notes on which the principal was due. If an event of default occurs as to any series of senior unsecured notes, the trustee or the holders of 25% in principal amount of the notes of such series may declare the principal of the notes of that series to be immediately due and payable. In addition, SCE's failure to pay any obligation for borrowed money in an aggregate amount in excess of $10 million would constitute an event of default with respect to all of the senior unsecured notes and SCE's outstanding quarterly income preferred securities if not cured within 30 days after notice from the trustee or the holders of the securities. No such notice has been received by SCE.

If a notice of default is received, SCE could cure the default only by paying $700 million in overdue principal and interest to holders of commercial paper and the 5⅞% notes. (SCE has also deferred payment of maturing commercial paper. See Note 6 for a further discussion). Making such payment would further impact SCE's liquidity. If a notice of default were received and not cured, and the trustee or noteholders were to declare an acceleration of the outstanding principal amount of the senior unsecured notes, SCE would not have the cash to pay the obligation and could be forced to declare bankruptcy.

In January 2001, three rating agencies lowered their credit ratings of Edison International, Edison Capital and SCE to substantially below investment grade. In mid-April, one agency removed the ratings from review for possible downgrade. The ratings remain under review for possible downgrade by the other two agencies.

To isolate EME from the credit downgrades of Edison International and SCE and to help preserve the value of EME, EME has adopted certain provisions (ring-fencing) in the form of amendments to its articles of incorporation and bylaws. The provisions include the appointment of an independent EME director whose consent is required for EME to: consolidate or merge with any entity; institute or consent to bankruptcy, insolvency or similar proceedings or actions; or declare or pay dividends unless certain conditions exist. Such conditions are: EME has an investment grade rating and receives rating agency confirmation that the dividend or distribution will not result in a downgrade, or such dividends do not exceed $32.5 million in any quarter and EME meets a certain interest coverage ratio for the immediately preceding four quarters. EME currently meets this interest coverage ratio.

A subsidiary of EME has deferred certain required capital expenditures at EME's Fiddler's Ferry and Ferrybridge power plants in the United Kingdom because the plants' financial performance has not met expectations. As a result, the EME subsidiary is in breach of technical requirements set forth in the plants' financing agreements related to the acquisition of the plants. Also, due to the lower financial performance, the subsidiary's debt service coverage ratio declined in 2000 below the threshold set in its financing documents. The subsidiary is currently in discussions with financing parties to revise the required capital expenditures program and to waive the breach of the financial ratio covenant for 2000, and related technical defaults. There are no assurances that an agreement can be met. The financing documents state that a breach of the financial ratio covenant constitutes an immediate event of default and, if the default is not waived, the financing parties are entitled to enforce their security over the subsidiary's assets, including the power plants. Due to the timing of its cash flows and debt service payments, EME's subsidiary utilized its debt service reserve to meet its debt service requirements in 2000.

The financial performance of the Ferrybridge and Fiddler's Ferry plants has not matched EME's expectations, largely due to lower energy power prices resulting from increased competition, climatic effects and uncertainties surrounding the new electricity trading arrangements. In accordance with asset impairment accounting standards, EME has evaluated the impairment of the Ferrybridge and Fiddler's Ferry power plants and has determined that no impairment exists. As a result of the change in power prices in the United Kingdom, EME is considering the sale of the Ferrybridge and Fiddler's Ferry plants. A decision has not been made regarding whether or not the sale of these plants will ultimately occur and, accordingly, these assets are not classified as held for sale. However, if a decision to sell the Ferrybridge and Fiddler's Ferry plants were made, it is likely that the fair value of the assets would be substantially below their book value at December 31, 2000.

On April 5, 2001, EME issued $600 million of 9.875% senior notes. The notes are due in April 2011.

Note 6. Short-Term Debt

Short-term debt is used to finance fuel inventories, balancing account undercollections and general cash requirements, including PX and ISO payments. Commercial paper intended to finance nuclear fuel scheduled to be used more than one year after the balance sheet date is classified as long-term debt in connection with refinancing terms under five-year term lines of credit with commercial banks.

Short-term debt consisted of:

In millions December 31,	**2000**	1999
Commercial paper	**$1,586**	$2,413
Bank loans	**1,355**	—
Floating rate notes	**600**	—
Amount reclassified as long-term	**(79)**	(71)
Unamortized discount	**(14)**	(14)
Other short-term debt	**472**	225
Total	**$3,920**	$2,553
Weighted-average interest rate	**7.2%**	6.5%

At December 31, 2000, Edison International and its subsidiaries had lines of credit totaling $3.6 billion, with approximately $400 million available. Credit lines are used to support commercial paper borrowings and bank loans. SCE had lines of credit totaling $1.65 billion with $125 million available for the long-term refinancing of certain variable-rate pollution-control debt. The nonutility subsidiaries had lines of credit of $274 million available to finance general cash requirements. Edison International's unsecured revolving lines of credit can be drawn at negotiated or bank index rates and have various expiration dates.

As of January 2001, SCE had borrowed the entire $1.65 billion in funds available under its credit lines. The proceeds were used in part to repurchase $420 million of pollution control bonds; the balance was retained as a liquidity reserve.

As of January 2001, Edison Capital had borrowed the entire $300 million in funds available under its credit lines. The proceeds were retained as a liquidity reserve. As a result, Edison Capital had no remaining credit lines available as of January 2001.

In late 2000, SCE was unable to complete the syndication of a $1 billion revolving credit agreement that was intended to finance current and expected balancing account undercollections and other operating requirements. In addition, SCE, Edison International and Edison Capital have been unable to market their commercial paper and other short-term financial instruments. And, in SCE's efforts to conserve cash, SCE has deferred payment of approximately $506 million of maturing commercial paper as of March 31, 2001.

Note 7. Preferred Securities

Preferred Stock of Utility

SCE's authorized shares of preferred and preference stocks are: $25 cumulative preferred — 24 million; $100 cumulative preferred — 12 million; and preference — 50 million. All cumulative preferred stocks are redeemable.

Mandatorily redeemable preferred stocks are subject to sinking-fund provisions. When preferred shares are redeemed, the premiums paid are charged to common equity.

Preferred stock redemption requirements for the next five years are: 2001 — zero; 2002 — $105 million; 2003 — $9 million; 2004 — $9 million; and 2005 — $9 million.

SCE's cumulative preferred stocks consisted of:

Dollars in millions, except per share amounts	December 31, 2000 Shares Outstanding	December 31, 2000 Redemption Price	2000	1999
Not subject to mandatory redemption:				
$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
Total			**$129**	$129
Subject to mandatory redemption:				
$100 par value:				
6.05% Series	750,000	$ 100.00	**$ 75**	$ 75
6.45	1,000,000	100.00	**100**	100
7.23	807,000	100.00	**81**	81
Total			**$256**	$256

In 1998, SCE redeemed 2.2 million shares of Series 5.8% and 193,000 shares of Series 7.23% preferred stock. SCE did not issue any preferred stock in the last three years.

SCE's Board of Directors did not declare the regular quarterly dividends for SCE's cumulative preferred stock in 2001. As long as these dividends remain unpaid, SCE cannot declare or pay future cash dividends on any series of preferred stock or on its common stock, and SCE cannot repurchase any shares of its common stock. As a result of the $2.5 billion charge to earnings during the fourth quarter 2000, SCE's retained earnings are now in a deficit position and therefore under California law, SCE will be unable to pay dividends as long as a deficit remains.

Company-Obligated Mandatorily Redeemable Securities of Subsidiary

EME issued, through a limited partnership, 3.5 million of 9.875% cumulative monthly income preferred securities in 1994, at a price of $25 per security. These securities are redeemable at the option of the partnership, in whole or in part, beginning November 1999 with mandatory redemption in 2024 at a redemption price of $25 per security plus accrued and unpaid distributions.

EME also issued, through a limited partnership, 2.5 million of 8.5% cumulative monthly income preferred securities in 1995, at a price of $25 per security. These securities are redeemable at the option of the partnership, in whole or in part, beginning August 2000 with mandatory redemption in 2025 at a redemption price of $25 per security plus accrued and unpaid distributions.

In 1999, Edison International issued, through affiliates, $500 million of 7.875% cumulative quarterly income preferred securities and $325 million of 8.6% cumulative quarterly income preferred securities at a price of $25 per security. The 7.875% securities have a stated maturity of July 2029 but are redeemable at the option of Edison International, in whole or in part, beginning July 2004. The 8.6% securities, which are guaranteed by Edison International, have a stated maturity of October 2029 but are redeemable at the option of Edison International, in whole or in part, beginning October 2004.

Other Preferred Securities

During 1999, EME issued, through an indirect, wholly owned affiliate, $120 million of flexible money market cumulative preferred stock. The stock issuance consisted of 600 Series A shares and

600 Series B shares, with a dividend rate of 5.74%. These securities were redeemable, in whole or in part, at the option of EME's affiliate, beginning May 2004, at $100,000 per share, plus accrued and unpaid dividends. On December 20, 2000, all Series A and Series B shares were redeemed at their liquidation preference of $100,000 per share, plus an additional premium of $3,785 per share and all unpaid dividends.

During 1999, EME issued through an indirect, wholly owned affiliate, $84 million of Class A redeemable preferred shares (16,000 shares priced at 10,000 New Zealand dollars per share with dividend rates between 6.19% and 6.86%). The shares are redeemable at their issuance price in June 2003.

During 1999, EME issued through an indirect, wholly owned affiliate, $125 million of retail redeemable preference shares (240 million shares priced at one New Zealand dollar per share with dividend rates between 5.0% and 6.37%). The shares are redeemable at their issuance price, according to the following schedule: June 2001 (64 million shares); June 2002 (43 million shares); and June 2003 (133 million shares).

Note 8. Income Taxes

Edison International's subsidiaries are included in Edison International's consolidated federal income tax and combined state franchise tax returns. Under income tax allocation agreements, each subsidiary calculates its own tax liability.

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

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

In millions December 31,	**2000**	1999
Deferred tax assets:		
Property-related	**$ 277**	$ 184
Unrealized gains or losses	**420**	453
Investment tax credits	**81**	113
Regulatory balancing accounts	**1,763**	68
Decommissioning	**98**	127
Unbilled revenue	**101**	122
Deferred income	**183**	185
Accrued charges	**548**	461
Loss carryforwards	**902**	69
Other	**133**	137
Total	**$4,506**	$1,919
Deferred tax liabilities:		
Property-related	**$4,239**	$4,562
Leveraged leases	**1,665**	1,280
Capitalized software costs	**264**	225
Regulatory balancing accounts	**1,632**	448
Decommissioning	**28**	23
Unrealized gains and losses	**317**	357
Other	**339**	590
Total	**$8,484**	$7,485
Accumulated deferred income taxes — net	**$3,978**	$5,566
Classification of accumulated deferred income taxes:		
Included in deferred credits	**$5,328**	$5,757
Included in current assets	**1,350**	191

The current and deferred components of income tax expense were:

In millions Year ended December 31,	**2000**	1999	1998
Current:			
Federal	**$(61)**	$(111)	$121
State	**—**	3	18
Foreign	**61**	(34)	15
	—	(142)	154
Deferred — federal and state:			
Accrued charges	**(98)**	(147)	(43)
Depreciation and basis differences	**(5)**	(57)	(14)
Investment and energy tax credits — net	**(41)**	(46)	(80)
Leveraged leases	**387**	315	346
Loss carryforwards	**(846)**	—	(33)
Regulatory balancing accounts	**(740)**	371	177
CTC amortization	**251**	7	63
Price risk management	**(38)**	—	—
State tax — privilege year	**30**	4	(1)
Other	**51**	(11)	(107)
	(1,049)	436	308
Total	**$(1,049)**	$ 294	$462

The composite federal and state statutory income tax rate was 40.551% for all years presented.

The federal statutory income tax rate is reconciled to the effective tax rate below:

Year ended December 31,	**2000**	1999	1998
Federal statutory rate	**35.0%**	35.0%	35.0%
Foreign earnings reinvestment	**0.4**	(4.4)	—
Housing credits	**2.0**	(6.9)	(5.7)
Capital loss utilization	**—**	(4.7)	—
Capitalized software	**0.4**	(2.5)	(0.6)
Property-related and other	**(7.1)**	9.7	10.0
Investment and energy tax credits	**1.4**	(4.7)	(5.7)
State tax — net of federal deduction	**3.0**	10.4	7.5
Effective tax rate	**35.1%**	31.9%	40.5%

Note 9. Employee Compensation and Benefit Plans

Employee Savings Plan

Edison International has a 401(k) defined-contribution savings plan designed to supplement employees' retirement income. The plan received employer contributions of $41 million in 2000, $31 million in 1999 and $18 million in 1998.

Pension Plan and Postretirement Benefits Other Than Pensions

Edison International has a noncontributory, defined-benefit pension plan that covers employees meeting minimum service requirements. Edison International's utility operations recognize pension expense as calculated by the actuarial method used for ratemaking. In April 1999, Edison International adopted a cash balance feature for its pension plan.

Most 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.

Information on plan assets and benefit obligations is shown below:

In millions Year ended December 31,	Pension Benefits 2000	1999	Other Postretirement Benefits 2000	1999
Change in benefit obligation				
Benefit obligation at beginning of year	**$2,121**	$ 2,281	**$1,547**	$1,563
Service cost	**74**	70	**45**	49
Interest cost	**159**	149	**129**	111
Plan amendment	**—**	(26)	**—**	(5)
Acquisition	**—**	10	**—**	81
Actuarial loss (gain)	**92**	(221)	**231**	(198)
Benefits paid	**(185)**	(142)	**(62)**	(54)
Benefit obligation at end of year	**$2,261**	$ 2,121	**$1,890**	$1,547
Change in plan assets				
Fair value of plan assets at beginning of year	**$3,112**	$ 2,576	**$1,283**	$1,029
Actual return on plan assets	**143**	627	**(41)**	186
Employer contributions	**39**	51	**20**	122
Benefits paid	**(185)**	(142)	**(62)**	(54)
Fair value of plan assets at end of year	**$3,109**	$ 3,112	**$1,200**	$1,283
Funded status	**$ 848**	$ 991	**$ (690)**	$ (264)
Unrecognized net loss (gain)	**(741)**	(1,019)	**160**	(218)
Unrecognized transition obligation	**23**	29	**323**	350
Unrecognized prior service cost	**115**	128	**(3)**	(3)
Recorded asset (liability)	**$ 245**	$ 129	**$ (210)**	$ (135)
Discount rate	**7.25%**	7.75%	**7.5%**	8.0%
Rate of compensation increase	**5.0%**	5.0%	**—**	—
Expected return on plan assets	**8.5%**	7.5%	**8.2%**	7.5%

Expense components were:

In millions Year ended December 31,	Pension Benefits 2000	1999	1998	Other Postretirement Benefits 2000	1999	1998
Service cost	**$ 74**	$ 70	$ 63	**$ 45**	$ 49	$ 43
Interest cost	**159**	149	143	**129**	111	100
Expected return on plan assets	**(270)**	(190)	(172)	**(106)**	(80)	(62)
Net amortization and deferral	**(40)**	12	14	**27**	27	28
Expense under accounting standards	**(77)**	41	48	**95**	107	109
Regulatory adjustment — deferred	**88**	14	11	**—**	—	—
Total expense recognized	**$ 11**	$ 55	$ 59	**$ 95**	$107	$109

The assumed rate of future increases in the per-capita cost of health care benefits is 11.0% for 2001, gradually decreasing to 5.0% for 2008 and beyond. Increasing the health care cost trend rate by one percentage point would increase the accumulated obligation as of December 31, 2000, by $311 million and annual aggregate service and interest costs by $34 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated obligation as of December 31, 2000, by $264 million and annual aggregate service and interest costs by $28 million.

Phantom Stock Options

Phantom stock option performance awards (also known as affiliate options) were developed for two affiliate companies, EME and Edison Capital, as part of the Edison International long-term incentive compensation program for senior management. Each phantom option could be exercised to realize any appreciation in the deemed value of one hypothetical share of EME or Edison Capital stock over exercise prices. Exercise prices for EME and Edison Capital phantom options were escalated on an annually compounded basis over the grant price by a factor linked to each affiliate's cost of capital. The deemed values of the phantom stock were recalculated annually as determined by a formula linked to the value of its portfolio of investments, less general and administrative costs. The options had a 10-year term with one-third of the total award vesting in each of the first three years of the award term. For options awarded in 1998 and 1999, one-fourth of the total award vested in each of the first four years of the award term.

Compensation expense recorded with respect to the phantom stock options was $13 million in 2000 (before the $60 million adjustment referred to below), $157 million in 1999 and $53 million in 1998.

Edison International elected to not issue additional phantom options after 1999. In January 2000, the Board of Directors preliminarily approved an exchange offer to the holders of outstanding phantom options. A revised exchange offer was subsequently approved and all holders of phantom stock options accepted the revised offer. The exchange offer was completed in August 2000. The exchange offer was principally for cash, with a portion exchanged for stock equivalent units relating to Edison International common stock. The vested cash payment occurred in March 2001, and accrued interest from August 2000. The number of stock equivalent units was determined on the basis of $20.50 per share, and the stock equivalent units will receive dividend equivalents to the extent dividends are declared on Edison International common stock. Participants could elect to cash their vested stock equivalent units on either the first or third anniversary of the exchange offer date (August 2000) for an amount equal to the daily average of Edison International common stock (for 20 trading days preceding the elected payment date). Some participants have elected to defer payment of their cash and stock equivalent units. Since all of the outstanding phantom options have been terminated, there will be no future exercises of the phantom options.

Due to the lower valuation of the exchange offer, the liability for accrued incentive compensation was reduced by approximately $60 million in the third quarter of 2000.

Stock Option Plans

In 1998, Edison International shareholders approved the Edison International Equity Compensation Plan, replacing the Long-Term Incentive Compensation Program (prior program), which had been adopted by shareholders in 1992. Under the prior program, options on 2.9 million of Edison International common stock remain outstanding to officers and senior managers. The 1998 plan authorizes a limited annual award of Edison International common shares and options on shares. The annual authorization is cumulative, allowing subsequent issuance of previously unutilized awards. In May 2000, Edison International adopted an additional plan, the 2000 Equity Plan, which did not require shareholder approval.

Under the 1998 and 2000 plans, options on 17.1 million shares of Edison International common stock are currently outstanding to officers and senior managers.

Each option may be exercised to purchase one share of Edison International common stock, and is exercisable at a price equivalent to the fair market value of the underlying stock at the date of grant. Options expire 10 years after the date of grant, and vest over a period of up to five years. A portion of the executive long-term incentives for 2000 was awarded in the form of performance shares. The performance shares were restructured as retention incentives in December 2000, which will pay as a combination of Edison International common stock and cash if the executive remains employed at the end of the performance period. Performance shares may still be awarded in 2001 and 2002. No special stock options may be exercised before five years have passed unless the stock price appreciates to $25 (based on the average of 20 consecutive trading day closing prices). Edison International stock options awarded between 1994 and 1999 included a dividend equivalent feature. Dividend equivalents are accrued to the extent dividends are declared on Edison International common stock, and are subject to reduction unless certain performance criteria are met. Only a portion of the 1999 Edison International stock option awards included a dividend equivalent feature. The 2000 stock option awards did not include dividend equivalents. Future stock option awards are not expected to include dividend equivalents.

All stock options have a 10-year term. Options issued after 1997 generally vest in 25 percent annual installments over a four-year period, although the vesting period for the May 2000 grants does not begin until May 2001. Stock options issued prior to 1998 had a three-year vesting period with one-third of the total award vesting after each of the first three years of the award term. If an option holder retires, dies or is permanently and totally disabled (qualifying event) during the vesting period, the unvested options will vest on a pro rata basis.

Unvested options of any person who has served in the past on the SCE Management Committee (which was dissolved in 1993) will vest and be exercisable upon a qualifying event. If a qualifying event occurs, the vested options may continue to be exercised within their original terms by the recipient or beneficiary. If an option holder is terminated other than by a qualifying event, options which had vested as of the prior anniversary date of the grant are forfeited unless exercised within 180 days of the date of termination. All unvested options are forfeited on the date of termination.

The performance shares values are accrued ratably over a three-year performance period. Edison International measures compensation expense related to stock-based compensation by the intrinsic value method. Compensation expense recorded under the stock-compensation program was $5 million in 2000, $5 million in 1999 and $9 million in 1998.

Stock-based compensation expense under the fair value method of accounting would have resulted in pro forma earnings (loss) of $(1.954) billion for 2000, $621 million for 1999 and $668 million for 1998, and in pro forma basic earnings (loss) per share of $(5.87) for 2000, $1.79 for 1999 and $1.86 for 1998.

The fair value for each option granted, reflecting the basis for the above pro forma disclosures, was determined on the date of grant using the Black-Scholes option-pricing model. The following assumptions were used in determining fair value through the model:

December 31,	**2000**	1999
Expected life	**7 years-10 years**	7 years
Risk-free interest rate	**4.7%-6.0%**	5.0%-5.5%
Expected volatility	**17%-46%**	18%

The application of fair-value accounting to calculate the pro forma disclosures above is not an indication of future income statement effects. The pro forma disclosures do not reflect the effect of fair-value accounting on stock-based compensation awards granted prior to 1995.

A summary of the status of Edison International's stock options is as follows:

	Share Options	Exercise Price	Weighted Average Exercise Price	Weighted Average Fair Value At Grant	Weighted Average Remaining Life
Outstanding, December 31, 1997	**4,411,666**	$14.56—$25.19	$18.76		7 years
Granted	**1,639,300**	$26.78—$29.34	$27.25	$6.42	
Expired	**—**	—	—		
Forfeited	**(46,171)**	$17.63—$29.88	$26.07		
Exercised	**(573,527)**	$14.56—$29.88	$17.33		
Outstanding, December 31, 1998	**5,431,268**	$14.56—$29.34	$21.52		7 years
Granted	**3,045,949**	$24.81—$28.13	$28.10	$6.45	
Expired	**—**	—	—		
Forfeited	**(6,805)**	$28.13—$28.80	$28.65		
Exercised	**(368,264)**	$14.56—$25.75	$18.72		
Outstanding, December 31, 1999	**8,102,148**	$14.56—$29.34	$24.04		7 years
Granted	**13,373,680**	$15.88—$28.13	$21.02	$5.63	
Expired	**—**	—	—		
Forfeited	**(1,183,760)**	$15.94—$28.94	$23.19		
Exercised	**(517,396)**	$14.56—$28.13	$19.35		
Outstanding, December 31, 2000	**19,774,672**	$14.56—$29.34	$22.24		8 years

The number of options exercisable and their weighted average exercise prices at December 31, 2000, 1999 and 1998 were 6,782,209 at $23.27, 5,018,556 at $21.63, and 3,805,755 at $19.72, respectively.

Note 10. Jointly Owned Utility Projects

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

The investment in each project as of December 31, 2000, was:

In millions	Original Cost of Facility	Accumulated Depreciation and Amortization	Under Construction	Ownership Interest
Transmission systems:				
Eldorado	$ 41	$ 11	$ 1	60%
Pacific Intertie	230	80	6	50
Generating stations:				
Four Corners Units 4 and 5 (coal)	463	351	3	48
Mohave (coal)	327	240	3	56
Palo Verde (nuclear)[1]	1,624	1,399	15	16
San Onofre (nuclear)[1]	4,268	3,874	22	75
Total	$6,953	$5,955	$50	

(1) Regulatory assets, which were written off as a charge to earnings as of December 31, 2000, as discussed in Notes 1 and 3.

Note 11. Commitments

Leases

Leveraged Leases

Edison Capital is the lessor in several leveraged-lease agreements with terms of 24 years to 38 years. All operating, maintenance, insurance and decommissioning costs are the responsibility of the lessees. The total cost of these facilities was $7.5 billion and $5.5 billion at December 31, 2000, and 1999, respectively.

The equity investment in these facilities is 19% of the purchase price. The remainder is nonrecourse debt secured by first liens on the leased property. The lenders have accepted their security interests as their only remedy if the lessee defaults.

The net investment in leveraged leases consisted of:

In millions December 31,	**2000**	1999
Rentals receivable (net of principal and interest on nonrecourse debt)	**$ 3,827**	$ 2,990
Unearned income	**(1,531)**	(1,145)
Investment in leveraged leases	**2,296**	1,845
Estimated residual value	**57**	58
Deferred income taxes	**(1,665)**	(1,280)
Net investment in leveraged leases	**$ 688**	$ 623

Operating Leases

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

During 2000, EME entered into a sale-leaseback transaction for certain equipment, primarily Illinois peaker power units, with a third-party lessor for $300 million. In connection with the sale-leaseback, EME purchased $255 million of notes issued by the lessor that accrue interest at a variable rate depending on EME's credit rating. The notes are due and payable in five years. Also during 2000, EME entered into a sale-leaseback transaction for power facilities, located in Illinois, with third-party lessors for an aggregate purchase price of $1.4 billion. The lease costs for the power facilities will be levelized over the terms of the power facilities' respective leases. The gain recognized on the sale of the power plants and equipment has been deferred and is being amortized over the terms of the respective leases. Lease payments are included in the table below.

Estimated remaining commitments for noncancelable leases at December 31, 2000, were:

Year ended December 31,	In millions
2001	$ 196
2002	212
2003	210
2004	232
2005	269
Thereafter	3,838
Total	$4,957

In December 2000, EME entered into agreements involving the construction of new projects. Under the terms of one of the agreements, the lessor, as owner of the projects, is responsible for the development and construction costs (approximately $986 million) of the new projects using turbines procured by EME. EME will supervise the development and construction of the projects as the agent of the lessor and upon completion of construction of each project, EME will lease the projects from the lessor. In connection with the lease, EME has provided a residual value guarantee to the lessor at the end of the lease term. EME is required to deposit treasury notes equal to 103% of the construction costs as collateral for the lessor which can only be used under certain circumstances involving default of EME's performance obligations during construction. Minimum lease payments under this agreement (included in the table above) are $3 million in 2003, $28 million in 2004 and $50 million in 2005. The lease agreement provides a purchase option based on the lease balance which can be exercised at any time during the term. The lease term ends in 2010.

Nuclear Decommissioning

Decommissioning is estimated to cost $2.1 billion in current-year dollars, based on site-specific studies performed in 1998 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 in the near term. SCE estimates that it will spend approximately $8.6 billion through 2060 to decommission its nuclear facilities. This estimate is based on SCE's current dollar decommissioning costs, escalated at rates ranging from 0.3% to 10.0% (depending on the cost element) annually. These costs are expected to be funded from independent decommissioning trusts, which, effective June 1999, receive contributions of approximately $25 million per year. SCE estimates annual after-tax earnings on the decommissioning funds of 3.9% to 4.9%.

SCE plans to decommission its nuclear generating facilities by a prompt removal method authorized by the Nuclear Regulatory Commission. The operating licenses expire in 2022 for San Onofre Units 2 and 3, and in 2026 and 2028 for the Palo Verde units. SCE could decommission San Onofre Units 2 and 3 as early as 2013. Palo Verde is planned to be decommissioned at the end of its operating license. Decommissioning costs, which are recovered through non-bypassable customer rates over the term of each nuclear facility's operating license, are recorded as a component of depreciation expense.

Decommissioning of San Onofre Unit 1 (shut down in 1992 per CPUC agreement) started in 1999 and will continue through 2008. All of SCE's San Onofre's Unit 1 decommissioning costs will be paid from its nuclear decommissioning trust funds.

Decommissioning expense was $106 million in 2000, $124 million in 1999 and $164 million in 1998. The accumulated provision for decommissioning, excluding San Onofre Unit 1 and unrealized holding gains, was $1.4 billion at December 31, 2000, and $1.3 billion at December 31, 1999. The estimated cost (recorded as a liability) to decommission San Onofre Unit 1 is approximately $342 million as of December 31, 2000.

Decommissioning funds collected in rates are placed in independent trusts, which, together with accumulated earnings, will be utilized solely for decommissioning.

Trust investments (cost basis) include:

In millions	Maturity Dates	December 31,	**2000**	1999
Municipal bonds	2001-2034		**$ 548**	$ 684
Stocks	—		**531**	482
U.S. government issues	2001-2029		**421**	351
Short-term and other	2001		**220**	133
Total			**$1,720**	$1,650

Trust fund earnings (based on specific identification) increase the trust fund balance and the accumulated provision for decommissioning. Net earnings were $38 million in 2000, $58 million in 1999 and $63 million in 1998. Proceeds from sales of securities (which are reinvested) were $4.7 billion in 2000, $2.6 billion in 1999 and $1.2 billion in 1998. Approximately 90% of the trust fund contributions were tax deductible.

Other Commitments

SCE and EME have fuel supply contracts which require payment only if the fuel is made available for purchase. Certain SCE gas and coal fuel contracts require payment of certain fixed charges whether or not gas or coal is delivered.

SCE has power-purchase contracts with certain qualifying facilities (cogenerators and small power producers) and other utilities. These contracts provide for capacity payments if a facility meets certain performance obligations and energy payments based on actual power supplied to SCE. There are no requirements to make debt-service payments. As a result of the utility industry restructuring, SCE has entered into purchased-power settlements to end its contract obligations with certain qualifying facilities. The settlements are reported as power purchase contracts on the balance sheets.

SCE has unconditional purchase obligations for part of a power plant's generating output, as well as firm transmission service from another utility. Minimum payments are based, in part, on the debt-service requirements of the provider, whether or not the plant or transmission line is operable. SCE's minimum commitment under both contracts is approximately $159 million through 2017. The purchased-power contract is expected to provide approximately 5% of current or estimated future operating capacity, and is reported as power purchase contracts (approximately $31 million). The transmission service contract requires a minimum payment of approximately $6 million a year.

Certain commitments for the years 2001 through 2005 are estimated below:

In millions	2001	2002	2003	2004	2005
Fuel supply contracts	$989	$760	$501	$405	$338
Purchased-power capacity payments	647	644	637	635	632

SCE and EME's projected construction expenditures for 2001 total approximately $1.1 billion. The construction programs are subject to periodic review and revision, and actual construction costs may vary from estimates because of numerous factors.

EME has firm commitments related to its Italian wind projects to make equity contributions of $3 million, and $17 million for asset purchases. EME also has contingent obligations to make additional contributions of $83 million, primarily for equity support guarantees related to the Paiton project in Indonesia and the ISAB project in Italy.

SCE has deferred payment to certain QFs for power purchases (as discussed in Notes 2 and 3). Four of these QFs are owned by partnerships in which EME has interests. Some of these QFs, have sought to minimize their exposure by reducing deliveries under power purchase agreements. As a result of the payment deferrals, certain partnerships have called on the partners to provide additional capital to fund operating costs of the power plants. From January 2001 through March 31, 2001, EME subsidiaries have made equity contributions of approximately $115 million to meet capital calls by these partnerships. EME's subsidiaries may be required to make additional capital contributions to the partnerships.

Edison Capital has commitments of $228 million to fund affordable housing, and energy and infrastructure investments.

Note 12. Contingencies

In addition to the matters disclosed in these notes, Edison International 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.

Energy Crisis Issues

In December 2000, a first amended complaint to a class action securities lawsuit (originally filed in October 2000) was filed in federal district court in Los Angeles against SCE and Edison International. On March 5, 2001, a second amended complaint was filed that alleges that SCE and Edison International are engaging in fraud by over-reporting and improperly accounting for the TRA undercollections. The second amended complaint is supposedly filed on behalf of a class of persons who purchased Edison International common stock beginning June 1, 2000, and continuing until such time as TRA-related undercollections are recorded as a loss on SCE's income statement. The response to the second amended complaint was due April 2, 2001. The response has been deferred pending resolution of motions to consolidate this lawsuit with another lawsuit filed on March 15, 2001. SCE believes that its current and past accounting for the TRA undercollections and related items is appropriate and in accordance with accounting principles generally accepted in the United States.

As of April 13, 2001, 17 additional lawsuits have been filed against SCE by QFs. The lawsuits have been filed by various parties, including geothermal or wind energy suppliers or owners of cogeneration projects. The lawsuits are seeking payments of at least $420 million for energy and capacity supplied to SCE under QF contracts, and in some cases for damages as well. Many of these QF lawsuits also seek an order allowing the suppliers to stop providing power to SCE and sell the power to other purchasers. SCE is seeking coordination of all of the QF-related lawsuits that have commenced in various California courts. On April 13, 2001, an order was issued assigning all pending cases to a coordination motion judge and setting a hearing on SCE's coordination petition by May 30, 2001. SCE cannot predict the outcome of any of these matters.

Environmental Protection

Edison International 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.

Edison International records its environmental liabilities when site assessments and/or remedial actions are probable and a range of reasonably likely cleanup costs can be estimated. Edison International 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, Edison International records the lower end of this reasonably likely range of costs (classified as other long-term liabilities at undiscounted amounts).

Edison International's recorded estimated minimum liability to remediate its 44 identified sites is $114 million. The ultimate costs to clean up Edison International'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. Edison International believes that, due to these uncertainties, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $272 million. The upper limit of this range of costs was estimated using assumptions least favorable to Edison International among a range of reasonably possible outcomes. SCE has sold all of its gas-fueled generation plants and has retained some liability associated with the divested properties.

The CPUC allows SCE to recover environmental-cleanup costs at certain sites, representing $45 million of its recorded liability, through an incentive mechanism. 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. Costs incurred at SCE's remaining sites are expected to be recovered through customer rates. SCE has recorded a regulatory asset of $75 million for its estimated minimum environmental-cleanup costs expected to be recovered through customer rates.

Edison International'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 Edison International may be held responsible for contributing to any costs incurred for remediating these sites. Thus, no reasonable estimate of cleanup costs can now be made for these sites.

Edison International expects to clean up its identified sites over a period of up to 30 years. Remediation expenditures in each of the next several years are expected to range from $5 million to $15 million. Recorded expenditures for 2000 were $13 million.

Based on currently available information, Edison International believes it is unlikely that it will incur amounts in excess of the upper limit of the estimated range and, based upon the CPUC's regulatory treatment of environmental-cleanup costs, Edison International 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.

Nuclear Insurance

Federal law limits public liability claims from a nuclear incident to $9.5 billion. SCE and other owners of San Onofre and Palo Verde have purchased the maximum private primary insurance available ($200 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 U.S. 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 Nuclear Regulatory Commission exempted San Onofre Unit 1 from this secondary level, effective June 1994. The maximum deferred premium for each nuclear incident is $88 million per reactor, but not more than $10 million per reactor may be charged in any one year for each incident. Based on its ownership interests, SCE could be required to pay a maximum of $175 million per nuclear incident. However, it would have to pay no more than $20 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. These policies are issued primarily by mutual insurance companies owned by utilities with nuclear facilities. 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 $19 million per year. Insurance premiums are charged to operating expense.

Paiton Project

A wholly owned subsidiary of EME owns a 40% interest and has a $490 million investment (at December 31, 2000) in the Paiton project, a 1,230-MW coal-fired power plant in Indonesia. The revenue schedule is higher in the early years and decreases over time. The plant's output is fully contracted with the state-owned electricity company for payment in Indonesian Rupiah, with the portion of such payments intended to cover non-Rupiah project costs (including returns to investors) adjusted to account for exchange rate fluctuation between the Indonesian Rupiah and the U.S. dollar. The project received substantial finance and insurance support from the Export-Import Bank of the United States and various other governmental agencies. The state-owned electricity company's payment obligations are supported by the Indonesian government.

The projected rate of growth of the Indonesian economy and the exchange rate of Indonesian Rupiah into U.S. dollars have deteriorated significantly since the Paiton project was contracted, approved and financed. The Paiton project's senior debt ratings have been reduced from investment grade to speculative grade based on the rating agencies' determination that there is increased risk that the state-owned electricity company might not be able to honor the power purchase agreement with Paiton. The Indonesian government has arranged to reschedule senior debt owed to foreign governments and has entered into discussions about rescheduling senior debt owed to private lenders.

One of the Paiton units began commercial operation in May 1999 and the other unit in July 1999. Because of the economic downturn, the state-owned electricity company has experienced low electricity demand and has therefore ordered no power from the Paiton plant through February 2000. The state-owned electricity company filed a lawsuit contesting the validity of its agreement to purchase electricity from the Paiton project. The lawsuit was withdrawn in January 2000, and in connection with this withdrawal, the parties entered into an interim agreement for the period through December 31, 2000, under which the levels of power ordered, and the fixed and energy payment amounts were agreed. As of December 31, 2000, the state-owned electricity company has made all fixed payments due under the interim agreement totalling $115 million and all payments due for energy delivered by the plant to the state-owned electricity company. As part of the continuing negotiations on a long-term restructuring of the revenue schedule, Paiton and the state-owned electricity company agreed in January 2001 on a Phase I agreement for the period from January 1, 2001, through June 30, 2001. This agreement provides for fixed monthly payments of $108 million over its six-month duration and for the payment for energy delivered to the state-owned electricity company from the plant during this period. Paiton and the state-owned electricity company intend to complete the negotiations of the future phases of a new long-term revenue schedule during the six-month duration of the Phase I agreement. To date, the state-owned electricity company has made all fixed and energy payments due under the Phase I agreement.

In October 1999, the project entered into an interim agreement with its lenders in which the lenders waived defaults during the term of the agreement and effectively agreed to defer payments of principal until July 31, 2000. The lenders had agreed to an extension of the agreement through December 31, 2000 (which has now been extended through December 31, 2001). Paiton has received lender approval of the Phase I agreement.

Under the terms of the power purchase agreement, the state-owned electricity company has been required to continue to pay for capacity and fixed operating costs once each unit and the plant achieved commercial operation. As of December 31, 2000, the state-owned electricity company had not paid invoices totaling $814 million for capacity charges and fixed operating costs under the power purchase agreement. All overdue amounts under the power purchase agreement continue to accumulate, minus the fixed monthly payments made under the year 2000 interim agreement and under the recently agreed Phase I agreement, with the payment of these overdue amounts to be dealt with in connection with the overall long-term restructuring of the revenue schedule. In this regard, under the Phase I agreement, Paiton has agreed that, so long as the Phase I agreement is complied with, it will seek to recoup no more than $590 million of the above overdue amounts, the payment of which is to be dealt with in connection with the overall revenue schedule restructuring.

Any material modifications of the power purchase agreement resulting from the continuing negotiation of a new long-term revenue schedule could require a renegotiation of the Paiton project's debt agreements. The impact of any such renegotiations with the state-owned electricity company, the Indonesian government or the project's creditors on EME's expected return on its investment in Paiton is uncertain at this time; however, EME believes that it will ultimately recover its investment in the project.

Spent Nuclear Fuel

Under federal law, the DOE is responsible for the selection and development of a facility for disposal of spent nuclear fuel and high-level radioactive waste. Such a facility was to be in operation by January 1998. However, the DOE did not meet its obligation. It is not certain when the DOE will begin accepting spent nuclear fuel from San Onofre or from other nuclear power plants.

SCE, as operating agent, has primary responsibility for the interim storage of its spent nuclear fuel at San Onofre. Current capability to store spent fuel is estimated to be adequate through 2005. SCE has not determined the costs for spent-fuel storage beyond that period which would require new and separate interim storage facilities. Extended delays by the DOE could lead to consideration of costly alternatives involving 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 one mill per kWh of nuclear-generated electricity sold after April 6, 1983.

Palo Verde on-site spent fuel storage capacity will accommodate needs until 2003 for Unit 2, and until 2004 for Units 1 and 3. Arizona Public Service Company, operating agent for Palo Verde, is constructing an interim fuel storage facility that is expected to be completed in 2002.

Note 13. Investments in Partnerships and Unconsolidated Subsidiaries

Edison International's nonutility subsidiaries have equity interests in energy projects, oil and gas and real estate investment partnerships. The difference between the carrying value of energy project investments and oil and gas and the underlying equity in the net assets was $490 million at December 31, 2000. The difference related to the energy projects is being amortized over the life of the projects; the difference related to oil and gas investment is amortized on a unit of production basis over the life of the reserves.

Summarized financial information of these investments was:

In millions	Year ended December 31,	**2000**	1999	1998
Revenue		**$ 2,844**	$ 2,338	$1,848
Expenses		**2,266**	1,872	1,525
Net income		**$ 578**	$ 466	$ 323

In millions	December 31,	**2000**	1999
Current assets		**$ 1,907**	$ 854
Other assets		**8,272**	9,487
Total assets		**$10,179**	$10,341
Current liabilities		**$ 1,299**	$ 1,644
Other liabilities		**6,192**	6,029
Equity		**2,688**	2,668
Total liabilities and equity		**$10,179**	$10,341

The undistributed earnings of investments accounted for by the equity method were $271 million in 2000 and $224 million in 1999.

Note 14. Business Segments

Edison International's reportable business segments include its electric utility operation segment (SCE), a nonutility power generation segment (EME), and a capital and financial services provider segment (Edison Capital). Its segments are based on Edison International's internal organization. They are separate business units and are managed separately. Edison International evaluates performance based on net income.

SCE is a rate-regulated electric utility which produces and supplies electric energy in central, coastal and Southern California. EME is a producer of electricity engaged in the development, ownership or leasing and operation of electric power generation facilities worldwide. EME also conducts energy trading and price risk management activities in markets where power generation facilities are open to competition. Edison Capital is a provider of capital and financial services with investments worldwide.

The accounting policies of the segments are the same as those described in the summary of significant accounting policies.

A significant source of revenue from EME's sale of energy and capacity is derived from sales to Commonwealth Edsion under power purchase agreements terminating in December 2004. Revenue from such sales was $1.1 billion in 2000. In January 2001, Commonwealth Edison assigned its rights to Exelon Generation Company. Exelon Generation will be obligated to make a capacity payment for the units under contract and an energy payment for the electricity produced by these units.

Edison International's business segment information was:

In millions	Electric Utility	Nonutility Power Generation	Capital & Financial Services	Corporate & Other[1]	Consolidated Edison International
2000					
Operating revenue	$ 7,870	$ 3,253[2]	$ 274	$ 320	$11,717
Depreciation, decommissioning and amortization	1,473	382	28	50	1,933
Interest and dividend income	173	45	10	(1)	227
Interest expense — net of amounts capitalized	572	689	57	70	1,388
Income tax expense (benefit)	(1,022)	82	(10)	(99)	(1,049)
Net income (loss)	(2,050)[3]	125	135	(153)	(1,943)
Total assets	15,966	15,017	3,713	404	35,100
Additions to and acquisition of property	1,096	399	1	39	1,535
1999					
Operating revenue	$ 7,548	$ 1,642[2]	$ 282	$ 224	$ 9,696
Depreciation, decommissioning and amortization	1,548	190	22	35	1,795
Interest and dividend income	69	42	4	(19)	96
Interest expense — net of amounts capitalized	483	353	41	17	894
Income tax expense (benefit)	438	(40)	(25)	(79)	294
Net income	484	130	129	(120)	623
Total assets	17,657[3]	15,534	2,712	326	36,229
Additions to and acquisition of property	986	8,309	—	(105)[4]	9,190
1998					
Operating revenue	$ 7,499	$ 894[2]	$ 235	$ 232	$ 8,860
Depreciation, decommissioning and amortization	1,546	87	20	9	1,662
Interest and dividend income	67	50	4	(13)	108
Interest expense — net of amounts capitalized	485	183	49	(7)	710
Income tax expense (benefit)	442	70	(15)	(35)	462
Net income	490	132	105	(59)	668
Total assets	16,947[3]	5,158	2,276	317	24,698
Additions to and acquisition of property	861	331	—	29	1,221

(1) Includes amounts from nonutility subsidiaries not significant as a reportable segment.
(2) Includes equity in income from investments of $267 million in 2000, $244 million in 1999 and $189 million in 1998.
(3) Net income (loss) available for common stock.
(4) Includes liabilities assumed and deferred credits of projects acquired in 1999.

Geographic Information

Electric power and steam generated domestically by EME is sold primarily under long-term contracts to electric utilities, through a centralized power pool, or under a power-purchase agreement with a term of up to five years. Projects in the United Kingdom and a project in Australia sell their energy through a centralized power pool (in the respective countries). Other electric power generated overseas is sold primarily under long-term contracts to electric utilities located in the country where the power is generated. All electric power generated by SCE was sold through the PX and ISO, as mandated by the CPUC. Effective December 15, 2000, the requirement for California utilities to buy and sell exclusively through the PX and ISO was eliminated.

Edison International's foreign and domestic revenue and assets information was:

In millions Year ended December 31,	**2000**	1999	1998
Revenue			
United States	**$10,262**	$8,657	$8,154
Foreign Countries:			
United Kingdom	**1,140**	748	449
Australia	**178**	209	199
Other	**137**	82	58
	$11,717	$9,696	$8,860

In millions December 31,	**2000**	1999
Assets		
United States	**$26,930**	$28,122
Foreign Countries:		
United Kingdom	**5,212**	5,032
Australia	**1,217**	1,398
Other	**1,741**	1,677
	$35,100	$36,229

Note 15. Acquisitions

Italian Wind Projects

In March 2000, EME completed its acquisition of Edison Mission Wind Power Italy B.V., formerly known as Italian Vento Power Corp. Energy 5 B.V. Edison Mission Wind owns a 50% interest in a series of wind-generated power projects in operation or under development in Italy. When all of the projects under development are completed, currently scheduled for 2002, the total capacity of these projects will be 283 MW. The purchase price of the acquisition is $44 million with equity contribution obligations of up to $16 million, depending on the number of projects that are ultimately developed. As of December 31, 2000, EME has paid $27 million toward the purchase price and $13 million in equity contributions.

Citizens Power

In September 2000, EME completed a transaction with P&L Coal Holdings Corporation and Gold Fields Mining Corporation to acquire the trading operations of Citizens Power LLC and a minority interest in certain structured transaction investments relating to long-term power purchase agreements. The purchase price of $45 million (funded from cash) was based on the sum of the fair market value of the trading portfolio and the structured transaction investments at the date of acquisition, plus $25 million. As a result of this acquisition, EME has expanded its trading operations beyond the traditional marketing of electric power. By the end of the third quarter of 2000, the Citizens' trading operations were merged into EME's marketing operations.

Sunrise Project

In November 2000, EME completed a transaction with Texaco Inc. to purchase a proposed 560-MW gas-fired combined cycle project (Sunrise Project) to be located in central California. The acquisition includes all rights, title and interest held by Texaco in the Sunrise Project, except that Texaco has an option to repurchase a 50% interest in the project prior to commercial operation. Phase I (construction of a single-cycle gas-fired facility) is scheduled to be completed in August 2001; Phase II (conversion to a combined-cycle gas-fired facility) is scheduled to be completed by June 2003. In December 2000, EME received the Energy Commission Certification and a permit to construct Phase I. The purchase price was $27 million. The acquisition was funded with cash. The project's estimated construction cost is approximately $400 million. As a part of this transaction, EME also acquired an option to purchase two gas turbines which it plans to utilize in the project, and provided Texaco with options to purchase two of the turbines under a lease agreement and to acquire 50% interests in 1,000 MW of future plant projects EME designates.

As discussed in Note 3, one of the elements of the Governor's proposal is the commitment of the entire output of this project to the State at cost-based rates for 10 years. As a result, EME is negotiating with the CDWR the detailed terms and conditions of a long-term, cost-based power purchase agreement. No assurance can be provided that EME will be successful in reaching a final agreement.

Homer City Electric Generating Station

In 1999, EME paid approximately $1.8 billion for Homer City. The purchase was partially financed by $1.5 billion of new loans, combined with corporate revolver borrowings and existing cash.

Contact Energy Ltd.

In 1999, EME completed a transaction with the New Zealand government to acquire 40% of the shares of Contact Energy Ltd (which owns and operates hydroelectric, geothermal and natural gas-fired generating plants, primarily in New Zealand). The remaining 60% of Contact Energy's shares were sold in an overseas public offering resulting in widespread ownership among the citizens of New Zealand and offshore investors. EME paid $635 million (1.2 billion New Zealand dollars), which was financed by a $120 million preferred securities of a wholly owned affiliate of EME, a $214 million EME credit facility, a $300 million equity contribution from Edison International and existing cash. During 2000, EME increased its share of ownership in Contact Energy to 42%.

Ferrybridge and Fiddler's Ferry

In 1999, EME paid approximately $2.0 billion (1.3 billion pounds Sterling) for the two plants. The coal-fired electric generating plants are located in the United Kingdom. Each plant has generating capacity of approximately 2,000 MW. The acquisition was funded primarily with a combination of net proceeds from an EME bond issuance, cash and an equity contribution from Edison International. The bonds were issued to a special purpose entity, which sold the variable rate coupons portion of the bonds to a special purpose entity that borrowed $1.3 billion under a Term Loan Facility to finance the purchase.

Roosecote Project

In 1999, EME paid approximately $16 million (9.6 million pounds Sterling) for the remaining 20% of the 220-MW natural gas-fired Roosecote project located in England.

Illinois Plants

In December 1999, EME through its wholly owned subsidiary, Midwest Generation LLC, completed the acquisition of Commonwealth Edison's fossil-fueled generating plants in Illinois. The $4.9 billion transaction was funded primarily with a combination of debt secured by a pledge of the stock of certain subsidiaries, EME corporate debt, equity contributions from Edison International and amounts paid by third-party lessors in connection with a lease transaction.

These acquisitions were accounted for utilizing the purchase method. Edison International's 2000 consolidated income statements reflect the operations of the Italian wind projects as of April 1, 2000, and Citizens Power as of September 1, 2000. Edison International's 1999 consolidated income statements reflect the operations of Homer City, Contact Energy, Ferrybridge and Fiddler's Ferry, Roosecote and the Illinois plants as of the date of their respective acquisitions.

In February 2001, EME completed the acquisition of a 50% interest in CBK Power Co. Ltd. in exchange for $20 million. CBK Power has entered into a 25-year build-rehabilitate-transfer-and-operate agreement with National Power Corporation related to a hydroelectric project located in the Philippines. Financing for this $460 million project has been completed with equity contributions of $117 million (EME's share is $59 million) required to be made upon completion of the rehabilitation and expansion, currently scheduled in 2003. Debt financing has been arranged for the remainder of the cost for this project.

	2000				
In millions, except per share amounts	**Total**	**Fourth**	**Third**	**Second**	**First**
Operating revenue	$11,717	$2,591	$3,653	$ 2,749	$2,724
Operating income (loss)	(1,729)	(3,777)	962	557	529
Net income (loss)	(1,943)	(2,550)	360	137	110
Per share:					
Basic earnings (loss)	(5.84)	(7.83)	1.11	0.41	0.32
Diluted earnings (loss)	(5.84)	(7.83)	1.10	0.41	0.32
Dividends declared	0.84	—	0.28	0.28	0.28
Common stock prices:					
High	30	24 7/16	26 5/8	21 15/16	30
Low	14 1/8	14 1/8	19	16 5/16	15 1/4
Close	15 5/8	15 5/8	19 21/64	20 1/2	16 9/16

	1999				
In millions, except per share amounts	**Total**	**Fourth**	**Third**	**Second**	**First**
Operating revenue	$ 9,696	$2,516	$2,963	$2,121	$2,096
Operating income	1,754	327	643	379	405
Net income	623	96	255	129	143
Per share:					
Basic earnings	1.79	0.28	0.74	0.37	0.41
Diluted earnings	1.79	0.28	0.73	0.37	0.41
Dividends declared	1.08	0.27	0.27	0.27	0.27
Common stock prices:					
High	29 5/8	29 5/8	27 3/8	29 1/4	28 15/16
Low	21 5/8	23 13/16	22 7/8	22 3/8	21 5/8
Close	26 3/16	26 3/16	24 5/16	26 3/4	22 1/4

Selected Financial and Operating Data: 1996-2000

Dollars in millions, except per share amounts	**2000**	1999	1998	1997	1996
Edison International and Subsidiaries					
Operating revenue	**$ 11,717**	$ 9,696	$ 8,860	$ 9,235	$ 8,545
Operating expenses	**$ 13,446**	$ 7,942	$ 7,076	$ 7,200	$ 6,503
Net income (loss)	**$ (1,943)**	$ 623	$ 668	$ 700	$ 717
Weighted-average shares of common stock outstanding (in millions)	**333**	348	359	400	437
Per share data:					
Basic earnings (loss)	**$ (5.84)**	$ 1.79	$ 1.86	$ 1.75	$ 1.64
Diluted earnings (loss)	**$ (5.84)**	$ 1.79	$ 1.84	$ 1.73	$ 1.63
Dividends paid	**$ 1.11**	$ 1.07	$ 1.03	$ 1.00	$ 1.00
Dividends declared	**$ 0.84**	$ 1.08	$ 1.04	$ 1.00	$ 1.00
Book value at year-end	**$ 7.43**	$ 15.01	$ 14.55	$ 14.71	$ 15.07
Market value at year-end	**$ 15⅝**	$ 26 3/16	$ 27⅞	$ 27 3/16	$ 19⅞
Dividend payout ratio (paid)	**N/A**	59.8%	55.4%	57.1%	61.0%
Rate of return on common equity	**(41.0)%**	12.2%	12.8%	11.7%	11.1%
Price/earnings ratio	**(2.7)**	14.6	15.0	15.5	12.1
Ratio of earnings to fixed charges	**(.87)**	1.85	2.33	2.41	2.42
Assets	**$ 35,100**	$ 36,229	$ 24,698	$ 25,101	$ 24,559
Long-term debt	**$ 12,150**	$ 13,391	$ 8,008	$ 8,871	$ 7,475
Common shareholders' equity	**$ 2,420**	$ 5,211	$ 5,099	$ 5,527	$ 6,397
Preferred stock subject to mandatory redemption	**$ 256**	$ 256	$ 256	$ 275	$ 275
Company-obligated mandatorily redeemable securities of subsidiaries holding solely parent company debentures	**$ 949**	$ 948	$ 150	$ 150	$ 150
Retained earnings	**$ 599**	$ 3,079	$ 2,906	$ 3,176	$ 3,753

Southern California Edison Company					
Operating revenue	**$ 7,870**	$ 7,548	$ 7,499	$ 7,953	$ 7,583
Net income (loss) available for common stock	**$ (2,050)**	$ 484	$ 490	$ 576	$ 621
Basic earnings (loss) per Edison International common share	**$ (6.16)**	$ 1.39	$ 1.37	$ 1.44	$ 1.42
Rate of return on common equity	**(67.6)%**	15.2%	13.3%	11.6%	12.1%
Peak demand in megawatts (MW)	**19,757**	19,122	19,935	19,118	18,207
Generation capacity at peak (MW)	**10,191**	10,474	10,546	21,511	21,602
Kilowatt-hour sales (in millions)	**83,436**	78,602	76,595	77,234	75,572
Customers (in millions)	**4.29**	4.36	4.27	4.25	4.22
Full-time employees	**12,593**	13,040	13,177	12,642	12,057

Edison Mission Energy					
Revenue	**$ 3,253**	$ 1,642	$ 894	$ 975	$ 844
Net income	**$ 125**	$ 130	$ 132	$ 115	$ 92
Assets	**$ 15,017**	$ 15,534	$ 5,158	$ 4,985	$ 5,153
Rate of return on common equity	**4.3%**	8.1%	14.8%	12.2%	8.8%
Ownership in operating projects (MW)	**22,759**	22,037	5,153	5,180	4,706
Full-time employees	**3,391**	3,245	1,180	1,140	940

Edison Capital					
Revenue	**$ 274**	$ 282	$ 235	$ 138	$ 49
Net income	**$ 135**	$ 129	$ 105	$ 61	$ 41
Assets	**$ 3,713**	$ 2,712	$ 2,276	$ 1,783	$ 1,423
Rate of return on common equity	**22.9%**	27.0%	30.2%	23.2%	17.7%
Full-time employees	**119**	115	85	85	70

Board of Directors*

John E. Bryson [1**]
Chairman of the Board, President and Chief Executive Officer, Edison International
A director since 1990

Warren Christopher [1,4]
Senior Partner,
O'Melveny & Myers,
Los Angeles, California
A director since 1971†

Stephen E. Frank [1***]
Chairman of the Board,
President and Chief Executive Officer, Southern California Edison Company
A director since 1995

Joan C. Hanley [2,4]
The Former General Partner and Manager, Miramonte Vineyards,
Rancho Palos Verdes, California
A director since 1980

Carl F. Huntsinger [1,4,5]
General Partner, DAE Limited Partnership, Ltd.,
Ojai, California
A director since 1983

Charles D. Miller [3,4,5]
Retired Chairman of the Board,
Avery Dennison Corporation,
Pasadena, California
A director since 1987

Luis G. Nogales [2,3]
President, Nogales Partners,
Los Angeles, California
A director since 1993

Ronald L. Olson [1,2,4]
Senior Partner,
Munger, Tolles and Olson,
Los Angeles, California
A director since 1995

James M. Rosser [1,2,3]
President, California State University, Los Angeles,
Los Angeles, California
A director since 1985

Robert H. Smith [3,5]
Managing Director,
Smith and Crowley Incorporated,
Pasadena, California
A director since 1987

Thomas C. Sutton [2,3,5]
Chairman of the Board and Chief Executive Officer,
Pacific Life Insurance Company,
Newport Beach, California
A director since 1995

Daniel M. Tellep [2,5]
Retired Chairman of the Board,
Lockheed Martin Corporation,
Bethesda, Maryland
A director since 1992

Edward Zapanta, M.D. [1,3,5]
Physician and Neurosurgeon,
Torrance, California
A director since 1984

1 Executive Committee
2 Finance Committee
3 Compensation and Executive Personnel Committee
4 Nominating Committee
5 Audit Committee

* Service includes combined Edison International and Southern California Edison Company Board memberships
** Edison International Board and Executive Committee only
*** Southern California Edison Company Executive Committee only

† 8/19/71 to 1/20/77
6/18/81 to 1/19/93
5/15/97 to present

EDISON INTERNATIONAL

John E. Bryson
Chairman of the Board, President and Chief Executive Officer

Bryant C. Danner
Executive Vice President and General Counsel

Theodore F. Craver, Jr.
Senior Vice President, Chief Financial Officer and Treasurer

Robert G. Foster
Senior Vice President, External Affairs

Mahvash Yazdi
Senior Vice President and Chief Information Officer

Jo Ann Goddard
Vice President, Investor Relations

Thomas M. Noonan
Vice President and Controller

Pedro J. Pizarro
Vice President, Technology Business Development

Joseph P. Ruiz
Vice President and General Auditor

Beverly P. Ryder
Vice President, Community Involvement, and Secretary

Andrea L. Simpson
Vice President, Corporate Communications

Anthony L. Smith
Vice President, Tax

SOUTHERN CALIFORNIA EDISON COMPANY

Stephen E. Frank
Chairman of the Board, President and Chief Executive Officer

Harold B. Ray
Executive Vice President, Generation Business Unit

Pamela A. Bass
Senior Vice President, Customer Service Business Unit

John R. Fielder
Senior Vice President, Regulatory Policy and Affairs

Robert G. Foster
Senior Vice President, External Affairs

Richard M. Rosenblum
Senior Vice President, Transmission and Distribution Business Unit

Mahvash Yazdi
Senior Vice President and Chief Information Officer

Emiko Banfield
Vice President, Shared Services

Robert C. Boada
Vice President and Treasurer

Clarence Brown
Vice President, Corporate Communications

Bruce C. Foster
Vice President, San Francisco Regulatory Operations

A.L. Grant
Vice President, Engineering and Technical Services

Lawrence D. Hamlin
Vice President, Power Production

Harry B. Hutchison
Vice President, Mass Customers

James A. Kelly
Vice President, Regulatory Compliance

Russell W. Krieger
Vice President, Nuclear Generation

J. Michael Mendez
Vice President, Labor Relations

Thomas M. Noonan
Vice President and Controller

Dwight E. Nunn
Vice President, Nuclear Engineering and Technical Services

Stephen E. Pickett
Vice President and General Counsel

Frank J. Quevedo
Vice President, Equal Opportunity

Joseph P. Ruiz
Vice President and General Auditor

W. James Scilacci
Vice President and Chief Financial Officer

Dale E. Shull, Jr.
Vice President, Power Delivery

Anthony L. Smith
Vice President, Tax

David Ned Smith
Vice President, Major Customers

Joseph J. Wambold
Vice President, Nuclear Business and Support Services

Beverly P. Ryder
Secretary

EDISON MISSION ENERGY

John E. Bryson
Chairman of the Board

Alan J. Fohrer
President and Chief Executive Officer

Robert M. Edgell
Executive Vice President

William J. Heller
Senior Vice President

Ronald L. Litzinger
Senior Vice President

Georgia R. Nelson
Senior Vice President

Kevin M. Smith
Senior Vice President and Chief Financial Officer

Raymond W. Vickers
Senior Vice President and General Counsel

Paul D. Jacob
President, Edison Mission Marketing and Trading

EDISON CAPITAL

John E. Bryson
Chairman of the Board

Thomas R. McDaniel
President and Chief Executive Officer

Ashraf T. Dajani
Senior Vice President

Richard E. Lucey
Senior Vice President and Chief Financial Officer

Larry C. Mount
Senior Vice President, General Counsel and Secretary

EDISON ENTERPRISES

Theodore F. Craver, Jr.
Chairman of the Board and Chief Executive Officer

Shareholder Information

Annual Meeting

The annual meeting of shareholders will be held on Monday, May 14, 2001, at 1:30 p.m., at the DoubleTree Hotel, 222 N. Vineyard Avenue, Ontario, California.

Stock Listing and Trading Information

Edison International Common Stock

The New York and Pacific stock exchanges use the ticker symbol EIX; daily newspapers list the stock as EdisonInt.

Preferred Securities and Preferred Stock

Edison International's preferred securities are listed on the New York Stock Exchange under the ticker symbols EIX prA for 7.875% QUIPS Series A and EIX prB for the 8.60% Series B. Previous day's closing prices, when traded, are listed in the daily newspapers in the New York Stock Exchange composite table. Southern California Edison Company's series of preferred stocks — 4.08%, 4.24%, 4.32% and 4.78% — are listed on the American and Pacific stock exchanges under the ticker symbol SCE. Previous day's closing prices, when traded, are listed in the daily newspapers in the American Stock Exchange composite table. The 6.05%, 6.45% and 7.23% series are not listed; however, the 6.45% and 7.23% series are traded over-the-counter. The preferred securities of Mission Capital, an affiliate of Edison Mission Energy, are listed on the New York Stock Exchange under the ticker symbol MEPrA for the 9.875% series and MEPrB for the 8.50% series.

Transfer Agent and Registrar

Wells Fargo Bank Minnesota, N.A., maintains shareholder records and is the transfer agent and registrar for Edison International common stock and Southern California Edison Company's preferred stocks. Shareholders may call Wells Fargo Shareowner Services (800) 347-8625, between 7 a.m. and 7 p.m. (Central Time), Monday through Friday, regarding:

- stock transfer and name-change requirements;
- address changes, including dividend addresses;
- electronic deposit of dividends;
- taxpayer identification number submission or changes;
- duplicate 1099 and W-9 forms;
- notices of, and replacement of, lost or destroyed stock certificates and dividend checks;
- direct debit of optional cash for dividend reinvestment;
- Edison International's Dividend Reinvestment and Stock Purchase Plan, including enrollments, withdrawals, terminations, transfers, sales, duplicate statements; and
- requests for access to online account information.

Inquiries may also be directed to:

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

Fax
(651) 450-4033

E-mail
stocktransfer@wellsfargo.com

Web Address
www.edisoninvestor.com

Dividend Reinvestment and Electronic Transfer

Shareholders can purchase additional common shares by reinvesting their quarterly dividends when paid. A prospectus for Edison International's Dividend Reinvestment and Stock Purchase Plan is available from Wells Fargo Shareowner Services.

Dividend checks can be electronically deposited directly to your financial institution. Enrollment forms are available upon request.

EDISON
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