EDISON
INTERNATIONAL®

2002 Annual Report

Edison International

Edison International, through its subsidiaries, is an electric power generator, distributor and structured finance provider. Headquartered in Rosemead, California, Edison International is the parent company of Southern California Edison – a regulated electric utility – and three nonutility businesses: Edison Mission Energy, Edison Capital and Mission Energy Holding Company.

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

Contents

Dear Fellow Shareholders:

During 2002, Edison International focused on three principal objectives: recovering from the adverse effects of the California power crisis, eliminating uncertainties that might impede our return to full financial health, and operating with excellence at every location and in every function.

These goals are not yet fully achieved, but we made solid progress in 2002. We removed $2.2 billion of overall debt; recovered most of our crisis-related power procurement costs; worked to persuade public officials to restore a healthy regulatory framework for the California utility industry; achieved a number of important restructurings and dispute resolutions, especially at our Edison Mission Energy (EME) subsidiary; and turned in an excellent operational year – in addition to reporting higher-than-expected earnings.

For 2003, we have three overarching goals: (1) finalize recovery of power crisis costs at Southern California Edison (SCE); (2) restructure the debt associated with EME; and (3) declare by year end a shareholder dividend to you, for distribution in early 2004.

THE UTILITY SIDE. In 2002, our operations were strong and our financial results good at SCE. In March, we repaid all undisputed past-due obligations associated with the power crisis, and at year end, we reported core earnings per share that were 83% higher than last year.

We also achieved a customer satisfaction rating that matched our previous record-high level in the pre-crisis years. In the end, our business – like every other – depends on how well we serve our customers; so continued confidence in our services is vital to us.

Maintaining a strong, reliable transmission and distribution system is always a priority. In 2002, we invested $600 million of new capital in that system and connected more than 63,000 new customers. Likewise, safe and high capacity operation of our San Onofre nuclear plant is crucial. We have met that test over the past year, including performing essential outage, monitoring, and upgrade work on both San Onofre units. Again, our nuclear team proved to be one of the best in the business.

We experienced one major disappointment on the utility side during 2002. The settlement we reached in October 2001 with the California Public Utilities Commission (CPUC) – which provides for us to recover $3.6 billion in costs incurred to keep the lights on during the crisis – was called into question by a federal court. While supporting us on the federal law issues involved, the court expressed misgivings about certain state law aspects of the agreement. The California Supreme Court has now agreed to review those issues and will likely rule on them some time this summer. Meanwhile, as of the end of February, we had recovered about $3 billion under that settlement. We continue to believe the settlement is legally sound, and the CPUC is continuing to support it fully.

Restoring a sound regulatory framework for providing electricity in California is essential to our business and to the state's economy. That process is incomplete, but important steps were taken in 2002. During the year, the CPUC put decisions in place that provide the revenues necessary to support our distribution and utility power generation businesses, including revenues for returns on the capital you invest in us.

In another set of decisions, the CPUC took important steps to take state government out of the business of buying or contracting for power and to return this responsibility to SCE, where it can be better managed for our customers' benefit. Preparing for the resumption of power procurement was a major effort by a large and skilled team at SCE. On January 1, 2003, SCE was ready; and is now, once again, procuring power for its customers. This task is complicated by the need to manage and integrate power supplied through contracts entered into by the state during the crisis.

New state legislation to limit the utilities' regulatory risk as they resume procurement became effective at year end. The implementing regulatory decisions, however, are not yet sufficiently complete or clear. Clarity and fairness in these rules will be essential to restoring a vitally important investment-grade credit rating at SCE.

In the next several years, more electricity infrastructure investment in Southern California will be necessary. New large transmission lines will be important, particularly to bring power supplies from the

Southwest into our region more effectively. SCE is preparing to provide these transmission system enhancements, and will seek acceptable regulatory terms and approvals to move forward. In addition, California will likely need new power plants in the next two to three years. We are now exploring what regulatory terms will be necessary to allow SCE to use its experience and skills in building, owning and operating new power generation facilities. Under the right terms, we could do this well, meeting customer needs and growing our utility business.

THE INDEPENDENT POWER SIDE. In 2002, the entire competitive power generation sector of our industry experienced an extraordinary reversal. For a decade prior to last year, this new and rapidly growing U.S. and international sector, known as "independent power," was seen in financial markets as a great new business opportunity. This enthusiasm led to a market-value "bubble" for unregulated power companies and to overbuilding as companies raced to construct new plants. Lenders provided loans that covered a very large part of the power plants' cost. As long as the industry remained in favor, these high debt levels were not seen as an impediment. EME itself retained some of the highest credit ratings in the sector. The Enron collapse and other factors, however, caused credit rating agencies to become more skeptical. In 2002, essentially every company in the sector – EME included – experienced credit downgrades to below investment-grade credit levels.

Within EME we have valuable, low-cost, environmentally sound and well-operated generating stations. We also have an extraordinarily able and experienced team of employees. During 2002, the people of EME took effective action to improve liquidity and cash. They operated plants above target availability and capacity factors. They further reduced operating costs. And they renegotiated, or otherwise resolved, several issues in order to cut future capital commitments over the next four years by about $800 million.

Throughout 2002, approximately 75% of EME's total power was sold under contracts with fixed-price terms to utilities and other distributors of power. However, as a result of contract elections made during the year, that percentage declined to about 50% effective at the beginning of this year. EME put into place a strong risk management function to manage and limit the volatility in earnings that is associated with having more power sold on shorter term hedge contracts and in "real time" commodity markets.

This year, we must address the debt structure associated with the EME business. With the credit market's altered perspective on this industry, lenders will not likely be ready to loan as much, or on the same terms, as in the past. The debt associated with EME is non-recourse to Edison International, the parent company, and also non-recourse to SCE and Edison Capital. Our total equity investment in the competitive generation business today stands at about $950 million. Although we continue to believe in the fundamental strengths of our EME business, we will not invest further Edison International equity in EME unless we are convinced that we can do so on terms that produce added value for you. This winter, wholesale power prices have strengthened considerably, benefiting low-cost power producers such as EME. But power plants are long-term investments and, to go forward effectively, EME needs to work out with its lenders a sound capital structure that reflects the long-term nature of the business.

Some Thoughts on Power Generation. Over the last decade, there has been extensive debate among policymakers across this country and around the world regarding whether customers are best served by regulated or competitive (sometimes given the misnomer of "deregulated") generation markets. In most jurisdictions, utilities have served customers reliably and at reasonable costs for long periods of time, but in some jurisdictions the effect of regulation has been to add very large costs for socially desired programs that ultimately burden the regulated system to the breaking point. To date, there is less worldwide experience with regions that employ primarily competitive markets to meet power needs. California is a case where "deregulation" resulted in chaos. In other places, such as the mid-Atlantic states in the U.S., and in New Zealand, where we operate, the new markets seem to be working reasonably well. The key ingredient appears to be truly well-designed markets, employing a sound legal framework including effective monitoring and the capacity to correct abuses promptly. The striking point for us is that, with the excellent skills and experience base of our employees, we can provide cost-competitive, reliable and well-managed power plants under either of these generation models, so long as the governance mechanisms are fair, sound, and predictable.

EDISON CAPITAL. In 2001, the effects of the power crisis undermined the credit strength of our Edison Capital business. Much of that strength was restored during 2002. Total debt was reduced and cash reserves were built to a level of nearly one-half billion dollars. Although that cash level is sufficient to meet Edison Capital's ongoing needs, it remains imperative that we continue to work toward our goal of restoring financial strength across all of Edison International. We will, therefore, make no further new investments in Edison Capital until that company-wide recovery is complete, targeted for this year end.

CONCLUSION. These have been volatile years across the industry and at our company. They have also been difficult for our long term shareholders. With perseverance and skill, SCE's employees worked effectively through the power crisis, never losing their primary focus on serving customers and shareholders well. In the past year, our EME team worked through a less-public, but equally demanding environment for that business, successfully resolving one substantial challenge after the next.

Difficult experiences test people. Those who meet the test strengthen their capacity to succeed in the future. I am confident that our people and our current business base provide a solid foundation for a strong and valuable future for your company.

Thank you for your continued investment in us.

Sincerely,

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

March 28, 2003

Management's Discussion and Analysis of Results of Operations and Financial Condition

This Management's Discussion and Analysis of Results of Operations and Financial Condition (MD&A) contains forward-looking statements. These statements are based on Edison International's knowledge of present facts, current expectations about future events and assumptions about future developments. Forward-looking statements are not guarantees of performance; they are subject to risks, uncertainties and assumptions that could cause actual future activities and results of operations to be materially different from those set forth in this discussion. Important factors that could cause actual results to differ include, but are not limited to, risks discussed below under "Financial Condition," "Market Risk Exposures" and "Forward-Looking Information and Risk Factors."

This MD&A includes information about Edison International and its principal subsidiaries, Southern California Edison Company (SCE), Edison Mission Energy (EME), Edison Capital and Mission Energy Holding Company (MEHC). Edison International is a holding company. SCE is a regulated public utility company providing electricity to retail customers in central, coastal, and southern California. EME is an independent power producer engaged in owning or leasing and operating electric power generation facilities worldwide and in energy trading and price risk management activities. Edison Capital is a global provider of capital and financial services in energy, affordable housing, and infrastructure projects focusing primarily on investments related to the production and delivery of electricity. MEHC was formed in June 2001, as a holding company for EME. In this MD&A, except when stated to the contrary, references to each of Edison International, SCE, MEHC, EME or Edison Capital mean each such company with its subsidiaries on a consolidated basis. References to Edison International (parent) or parent company mean Edison International on a stand-alone basis, not consolidated with its subsidiaries. References to SCE, MEHC, EME or Edison Capital followed by (stand alone) mean each such company alone, not consolidated with its subsidiaries.

This MD&A is presented in 13 major sections:

CURRENT DEVELOPMENTS

SCE Developments

Between May 2000 and June 2001, the cost of unregulated wholesale power in California rose above revenue collected in rates that were frozen in 1998 and SCE was not allowed by the CPUC to pass these excess costs through to its customers. As a result SCE incurred $4.7 billion (pre-tax) in write-offs related to its undercollected costs and generation-related regulatory assets through August 31, 2001. In October 2001, SCE entered into a settlement agreement with the California Public Utilities Commission (CPUC) that allowed SCE to recover $3.6 billion in past procurement-related costs through the creation of a procurement-related obligations account (PROACT) regulatory asset. The balance in this regulatory asset decreased to $574 million at year-end 2002 and SCE expects to recover the remaining balance by mid-2003.

The Utility Reform Network (TURN), a consumer advocacy group, and other parties appealed to the federal court of appeals seeking to overturn the district court judgment that approved the settlement agreement. In September 2002, an appeals court opinion affirmed the district court on all claims, with the exception of challenges founded upon California state law, which the appeals court referred to the California Supreme Court. On November 20, 2002, the California Supreme Court issued an order indicating that it would hear the case. The key issues in this matter are whether the district court judgment violated California's electric industry restructuring statute providing for a rate freeze and state laws requiring open meetings and public hearings. SCE continues to operate under the settlement agreement and to believe it is probable that SCE will ultimately recover its past procurement costs through regulatory mechanisms, including the PROACT. However, SCE cannot predict with certainty the outcome of the pending legal proceedings.

In January 2001, the state of California began purchasing power on behalf of SCE's customers because SCE's financial condition prevented it from purchasing power supplies for its customers. On January 1, 2003, SCE resumed power procurement of its residual net short position (the amount of energy needed to serve SCE's customers from sources other than its own generating plants, power purchase contracts and California Department of Water Resources (CDWR) contracts).

These and other matters are discussed in detail in "SCE's Regulatory Matters."

MEHC and EME Developments

A number of significant developments during late 2001 and 2002 have adversely affected independent power producers and subsidiaries of major integrated energy companies that sell a sizable portion of their generation into the wholesale energy market (sometimes referred to as merchant generators), including several of EME's subsidiaries, as discussed below. These developments included lower market prices in wholesale energy markets both in the United States and United Kingdom, significant declines in the credit ratings of most major market participants, decreased availability of debt financing or refinancing and a resulting decline of liquidity in the energy markets due to growing concern about the ability of counterparties to perform their obligations. In response to these developments, many merchant generators and power trading firms have announced plans to improve their financial position through asset sales, the cancellation or deferral of substantial new development, significant reduction in or elimination of trading activities, decreases in capital expenditures, including cancellations of orders for new turbines, and reductions in operating costs. In early 2003, wholesale energy prices have increased primarily due to colder-than-normal weather and increases in the prices for natural gas. However, the recent changes in wholesale energy prices may or may not continue throughout 2003. See "Market Risk Exposures—EME's Market Risks," for more information regarding forward market prices.

EME's Situation

Because of the 2000–2001 California power crisis and its indirect effect on EME and its subsidiaries, EME de-emphasized the development and acquisition of projects and focused primarily on enhancing the performance of its existing projects and on maintaining credit quality. As a result, during 2001 and early 2002, EME completed the sale of several non-strategic project investments. During 2002, EME undertook a further effort to reduce corporate overhead and other expenditures across the organization and to reduce debt.

In 2002, EME was affected by lower wholesale prices of energy and capacity, particularly at its Homer City facilities in Pennsylvania, and by the diminished ability to enter into forward contracts for the sale of power primarily from these facilities because of the credit constraints affecting EME and many of its counterparties. See the "Homer City Facilities" discussion in "Market Risk Exposures—EME's Market Risks."

EME's Illinois plants were largely unaffected by these developments in 2002 because Exelon Generation was under contract to buy substantially all of the capacity from these units during the entire year. However, as permitted by the power purchase agreements, Exelon Generation advised EME that it will not purchase under contract 2,684 MW of capacity from EME's coal-fired units and 1,864 MW of capacity from EME's Collins Station and small peaking units during 2003 and 2004. Exelon Generation has the further right to release 1,265 MW of capacity from EME's coal-fired units and 1,778 MW of capacity from EME's Collins Station and small peaking units for 2004. As a result, beginning in 2003, the portion of EME's generation that will be sold into the wholesale markets has significantly increased, thereby increasing EME's merchant risk. See the "Illinois Plants" discussion in "Market Risk Exposures—EME's Market Risks."

As a result of these and other factors, both Moody's Investors Service and Standard & Poor's Rating Service downgraded MEHC's credit rating, EME's credit rating and the credit rating of its largest subsidiary, Edison Mission Midwest Holdings, to below investment grade. See discussion in "Financial Condition—EME's Liquidity Issues." Furthermore, MEHC's independent accountants' audit opinion for the year ended December 31, 2002 contains an explanatory paragraph that indicates MEHC's consolidated financial statements have been prepared on a basis that MEHC will continue as a going concern and that the uncertainty about Edison Mission Midwest Holdings' ability to repay, extend or refinance Edison Mission Midwest Holdings' $911 million of debt due in December 2003 raises substantial doubt about MEHC's ability to continue as a going concern. Accordingly, MEHC's consolidated financial statements do not include any adjustments that might result from the resolution of this uncertainty.

Against this background, EME has undertaken a number of actions to reduce its commitments and expenditures, thereby improving its cash flow. These actions include:

- a reduction in its capital expenditure program by an aggregate of $363 million over the next five years as a result of the cancellation of an outstanding order for nine turbines and suspension of work on two selective catalytic reduction systems (commonly referred to as SCRs) for its Powerton Station;
- suspension, beginning in January 2003, of operations at Units 1 and 2 of its Will County plant and Units 4 and 5 of its Collins Station in Illinois in order to reduce operating costs;
- termination of the obligation of EME's subsidiary, Midwest Generation, LLC (Midwest Generation), to install 500 MW of new generating capacity in Chicago in exchange for a series of payments and other consideration;
- suspension of new business development activities; and
- implementation of plans to reduce annual general and administrative expenses by approximately $25 million.

In addition, EME continues to review the possibility of asset sales, but believes that current market conditions may inhibit its ability to obtain prices commensurate with its valuation of those investments that EME might offer for sale. For a discussion of EME's current financial condition, see "Financial Condition—EME's Liquidity Issues."

Significant Debt Maturity due December 2003

EME's largest subsidiary, Edison Mission Midwest Holdings has $911 million of debt maturing in December 2003. This $911 million of debt will need to be repaid, extended or refinanced. Edison Mission Midwest Holdings is not expected to have sufficient cash to repay the $911 million debt due in December 2003 and there is no assurance that EME will be able to repay, extend or refinance the Edison Mission Midwest Holdings debt obligation on similar terms and rates as the existing debt, on commercially reasonable terms, on the terms permitted under the MEHC financing documents entered into by MEHC in July 2001, or at all.

The below investment grade credit ratings at MEHC, EME and several of EME's subsidiaries, including Edison Mission Midwest Holdings, may adversely affect their ability to enter into new financings and, to the extent that new financings or amendments to existing financing arrangements are obtained, may adversely affect the terms and interest rates that can be obtained. Any future incremental reduction or withdrawal of one or more of EME's credit ratings or the credit ratings of its subsidiaries' credit ratings could have an additional adverse effect on their ability to access capital on acceptable terms, including their ability to refinance debt obligations as they mature. A failure to repay, extend or refinance Edison Mission Midwest Holdings' $911 million of debt as required by its terms would result in an event of default under the Edison Mission Midwest Holdings financing documents, which would permit the lenders to accelerate $808 million of indebtedness in addition to the $911 million which matures in December 2003. Furthermore, these events would trigger cross-defaults under agreements to which Edison Mission

Midwest Holdings and Midwest Generation are parties, including the Collins, Powerton and Joliet leases. An acceleration of debt and lease payments due under these agreements could result in a substantial claim for termination value under the EME guarantee of the Powerton and Joliet leases and could result in a default under EME's financing agreements. A default by EME on its financing arrangements or a default by one of its subsidiaries on indebtedness considered under the MEHC financing documents as having recourse to EME is likely to result in a default under the MEHC financing documents. These events could make it necessary for one or more of these companies to file a petition for reorganization under Chapter 11 of the United States Bankruptcy Code. Edison International's investment in MEHC, through a wholly owned subsidiary, as of December 31, 2002, was $953 million. MEHC's investment in EME, as of December 31, 2002, was $1.9 billion. See "Financial Condition—MEHC's (stand alone) Liquidity Issues" and "Off-Balance Sheet Transactions—EME's Off-Balance Sheet Transactions—Sale-Leaseback Transactions."

Edison Capital Developments

Edison Capital's liquidity improved in 2002 with the retirement of $324 million of outstanding debt and increased cash balances. Edison Capital has no debt maturities in 2003. As a provider of capital to both the energy and airline industries, which have been experiencing financial difficulties, Edison Capital's exposure to credit losses has increased. Specifically, in the fourth quarter of 2002, Edison Capital wrote off its investment related to two United Airlines aircraft leases, taking an after tax charge of $34 million. Edison Capital has leased three aircraft to American Airlines. American Airlines is reporting significant operating losses, and there is increasing concern that American Airlines may file bankruptcy or otherwise default on the leases. In the event of a bankruptcy or default by American Airlines or any voluntary restructure of the leases, Edison Capital could record a loss of up to $48 million in 2003.

RESULTS OF OPERATIONS

Edison International recorded earnings of $1.1 billion or $3.31 per share in 2002, compared to $1.0 billion or $3.18 per share in 2001, and a loss of $1.9 billion or $5.84 per share in 2000. The table below presents Edison International's earnings per share and net income for the years ended December 31, 2002, 2001 and 2000, and the relative contributions by its subsidiaries.

In millions, except per share amounts	EPS			Earnings (Loss)		
Year Ended December 31,	**2002**	2001	2000	**2002**	2001	2000
Earnings (Loss) from Continuing Operations:						
Core Earnings:						
SCE	**$ 2.30**	$ 1.25	$ 1.42	**$ 748**	$ 408	$ 471
EME	**0.26**	0.35	0.30	**82**	113	101
Edison Capital	**0.10**	0.26	0.41	**33**	84	135
Mission Energy Holding Company (stand alone)	**(0.29)**	(0.15)	—	**(94)**	(49)	—
Edison International (parent) and other	**(0.35)**	(0.41)	(0.38)	**(114)**	(132)	(125)
Edison International Core Earnings	**2.02**	1.30	1.75	**655**	424	582
SCE implementation of URG decision	**1.47**	—	—	**480**	—	—
SCE procurement and generation-related adjustment	—	6.07	(7.58)	—	1,978	(2,521)
Edison International Consolidated Earnings (Loss) from Continuing Operations	**3.49**	7.37	(5.83)	**1,135**	2,402	(1,939)
Loss from Discontinued Operations	**(0.18)**	(4.19)	(0.01)	**(58)**	(1,367)	(4)
Edison International Consolidated	**$ 3.31**	$ 3.18	$ (5.84)	**$ 1,077**	$ 1,035	$ (1,943)

Earnings (Loss) from Continuing Operations

Edison International's 2002 earnings from continuing operations were $1.1 billion, or $3.49 per share, compared with earnings of $2.4 billion, or $7.37 per share, in 2001, and a loss of $1.9 billion, or $5.83 per share, in 2000.

2002 vs. 2001

SCE's core earnings were $748 million in 2002, an increase of $340 million compared to last year. Core earnings exclude $480 million in 2002 earnings related to the implementation of the CPUC's utility retained generation (URG) decision and an adjustment of $2.0 billion in 2001 to establish the PROACT and record the recovery of SCE's past procurement-related costs. As of February 28, 2003, the remaining uncollected PROACT balance was $594 million. The 83% increase in SCE's core earnings primarily reflects increased revenue resulting from the CPUC's 2002 decision in SCE's performance-based rate-making (PBR) proceeding, increased earnings from SCE's larger rate base in 2002 compared to 2001, lower interest expense, PBR rewards from prior years and increased income from San Onofre Nuclear Generating Station (San Onofre) Units 2 and 3. The increase was partially offset by higher operating and maintenance expense.

EME's earnings from continuing operations in 2002 were $82 million, compared to $113 million in 2001. The decrease in earnings was primarily due to lower west coast energy prices, unplanned outages at the Homer City plant, gains related to gas swaps from EME's oil and gas activities, the implementation of a new accounting standard for derivatives in 2001, and other net charges during 2002 totaling $50 million, after tax, or $0.15 per share. These net charges included a $27 million loss from a settlement agreement that terminated the obligation to build additional generation in Chicago and a $66 million write-down of assets related to the cancellation of turbine orders, the suspension of the Powerton SCR project, and an impairment of goodwill, partially offset by a gain of $43 million from the settlement of a postretirement employee benefit liability. The decrease in earnings from continuing operations was partially offset by improved operating results at EME's Illinois, Loy Yang B and ISAB plants, income from the Paiton project in Indonesia, and lower state income taxes.

Edison Capital's earnings were $33 million in 2002 compared with $84 million in 2001. The decrease in earnings was primarily the result of a write-off of an investment in aircraft leases with United Airlines totaling $34 million, after tax, or $0.11 per share. Also contributing to the decline in earnings was lower earnings attributable to a maturing investment portfolio and gains in 2001 associated with asset sales. The decline in earnings was partially offset by lower interest expense and higher tax benefits.

The loss at Mission Energy Holding Company (stand alone) increased by $45 million reflecting the issuance of debt in mid-2001.

The loss for Edison International (parent company) and other decreased $18 million primarily from lower interest expense and a tax adjustment in 2001.

2001 vs. 2000

SCE's 2001 earnings of $2.4 billion included a $2.0 billion (after tax) net benefit to reflect the impact of the three procurement and generation-related adjustments: $2.1 billion (after tax) reestablishment of procurement-related regulatory assets and liabilities to establish PROACT, the recovery of $178 million (after tax) of previously written off generation-related regulatory assets, both of which are partially offset by $328 million (after tax) of net undercollected transition costs incurred between January and August 2001. SCE's $2.1 billion loss in 2000 included a $2.5 billion (after tax) write-off of regulatory assets and liabilities as of December 31, 2000. Excluding the $2.0 billion (after tax) net benefit in 2001 and the $2.5 billion (after tax) write-off in 2000, SCE's 2001 earnings were $408 million compared to $471 million in 2000. The $63 million decrease was primarily due to the February 2001 fire and resulting outage at San Onofre Unit 3 and lower kilowatt-hour sales, partially offset by the impact of fewer average common shares outstanding.

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. Based on a CPUC decision in March 2001, the $4.5 billion transition revenue account undercollection as of December 31, 2000 and the coal and hydroelectric balancing account overcollections were reclassified, and the transition cost balancing account (TCBA) balance was recalculated to be a $2.9 billion undercollection. As a result, SCE was unable to conclude that, under applicable accounting principles, the $2.9 billion TCBA undercollection (as recalculated above) and $1.3 billion (book value) of other net regulatory assets that were to be recovered through the TCBA mechanism by the end of the rate freeze were probable of recovery through the rate-making process as of December 31, 2000. As a result, SCE's December 31, 2000 income statement included a $4.0 billion charge to provisions for regulatory adjustment clauses and a $1.5 billion net reduction in income tax expense, to reflect the $2.5 billion (after tax) write-off.

Based on the CPUC's January 23, 2002 PROACT resolution, SCE was able to conclude that $3.6 billion in regulatory assets previously written off were probable of recovery through the rate-making process as of December 31, 2001. As a result, SCE's December 31, 2001 consolidated income statement included a $3.6 billion credit to provisions for regulatory adjustment clauses and a $1.5 billion charge to income tax expense, to reflect the $2.1 billion (after tax) credit to earnings.

EME's 2001 earnings from continuing operations of $113 million increased $12 million over 2000. The increase in 2001 reflects higher energy prices for EME's U.S. projects and increased earnings from oil and gas activities, partially offset by lower energy prices and capacity payments in the United Kingdom, the non-recurring affiliate stock option plan expense adjustment in 2000, and the partial termination of a lease for turbines.

Edison Capital's 2001 earnings of $84 million decreased $51 million from 2000. The decrease in 2001 was primarily due to both the contractual run-off of (i.e., as the average age of leases in the portfolio increases, earnings decline) and fewer assets in Edison Capital's lease portfolio. These decreases were partially offset by a net gain on asset sales and income from the syndication of affordable housing projects, as well as lower operating expenses.

Mission Energy Holding Company (stand alone), which was formed in 2001, showed a loss of $49 million in 2001, due to the issuance of new debt during the third quarter of 2001.

Edison International (parent company) incurred a loss of $132 million in 2001, compared to a $125 million loss in 2000. The increased loss in 2001 was mostly due to a prior-year tax adjustment.

The following subsections of "Results of Operations" discuss changes in various line items presented on the Consolidated Statements of Income (Loss).

Operating Revenue

More than 94% 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 following table sets forth the major changes in electric utility revenue:

In millions Year ended December 31,	2002 vs. 2001	2001 vs. 2000
Electric utility revenue –		
Rate changes (including refunds)	$ 565	$ 2,338
Direct access credit	(604)	273
Interruptible noncompliance penalty	(8)	117
Sales volume changes	684	(2,402)
Other (including intercompany transactions)	(52)	(76)
Total	$ 585	$ 250

Electric utility revenue increased in 2002 as compared to 2001 (as shown in the table above) primarily due to a 3¢-per-kWh surcharge authorized by the CPUC as of March 27, 2001. Although the surcharge was authorized as of March 27, 2001, it was not collected in rates until the CPUC determined how the rate increase would be allocated among SCE's customer classes, which occurred in May 2001. In addition, the increase in revenue resulted from an increase in sales volume primarily due to SCE providing its customers with a greater volume of energy generated from its own generating plants and power purchase contracts, rather than the CDWR purchasing power on behalf of SCE's customers. Amounts SCE bills to and collects from its customers for electric power purchased and sold by the CDWR to SCE's customers (beginning January 17, 2001) and CDWR bond-related costs (beginning November 15, 2002) are being remitted to the CDWR and are not recognized as revenue by SCE. These amounts were $1.4 billion and $2.0 billion for the years ended December 31, 2002 and 2001, respectively. The increase in electric utility revenue was partially offset by a decrease in revenue arising from an increase in credits given to direct access customers in 2002, compared to 2001, due to a significant increase in the number of direct access customers.

Electric utility revenue increased in 2001 (as shown in the table above), primarily due to the 4¢-per-kWh (1¢ in January 2001 and 3¢ in June 2001) surcharge effective in 2001, the effects of the reduced credits given to direct access customers in 2001 and an increase in revenue related to penalties customers incurred for not complying with their interruptible contracts. The increases were partially offset by a decrease in retail sales volume primarily attributable to CDWR purchases on behalf of SCE customers and conservation efforts, as well as a decrease in revenue related to operation and maintenance services.

From 1998 through mid-September 2001, SCE's customers were able to choose to purchase power directly from an energy service provider other than SCE (thus becoming direct access customers) or continue to have SCE purchase power on their behalf. On March 21, 2002, the CPUC issued a decision affirming that new direct access arrangements entered into by SCE's customers after September 20, 2001 were invalid. Direct access arrangements entered into prior to September 20, 2001 remain valid. Most direct access customers continue to be billed by SCE, but are given a credit for the generation costs SCE saves by not serving them. Electric utility revenue is reported net of this credit. See "Direct Access – Historical Procurement Charge" discussion under "SCE's Regulatory Matters—Direct Access Proceedings" below.

During 2000, as a result of the power shortage in California, SCE's customers on interruptible rate programs (which provide for lower generation rates 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, those customers were assessed significant penalties. On January 26, 2001, the CPUC waived the penalties assessed to noncompliant customers after October 1, 2000 until the interruptible programs could be reevaluated.

Nonutility power generation revenue increased in both 2002 and 2001. The 2002 increase was primarily due to EME's consolidation of Contact Energy for a full year in 2002, compared to a partial year in 2001 (ownership interest increased to 51%, effective June 1, 2001), and increased revenue from the Illinois plants and First Hydro plant. These increases were partially offset by decreased revenue from Homer City. The 2001 increase was primarily due to increases at EME related to the consolidation of Contact Energy revenue for a partial year in 2001, as compared to the equity method of accounting in 2000, higher revenue at Homer City and increased income from its oil and gas activities primarily from realized and unrealized gains for a gas swap purchased to hedge a portion of EME's gas price risk related to its oil and gas investments. These increases were partially offset by a decrease at EME's First Hydro plant due to lower energy and capacity prices in the U.K. and a reduction in trading activities in 2001.

Electric power generated at EME's Illinois plants is sold under agreements with Exelon Generation. Exelon Generation is obligated to make capacity payments for the Illinois plants under contract and an energy payment for electricity produced by these plants. EME's revenue under these agreements was $1.1 billion for each of the years ended December 31, 2002, 2001 and 2000. This represents 40%, 42% and 48% of nonutility power generation revenue for 2002, 2001 and 2000, respectively. See "Illinois Plants" discussion in "Market Risk Exposures—EME's Market Risks—Commodity Price Risk."

EME's third quarter nonutility power generation revenue are materially higher than revenue related to other quarters of the year because warmer weather during the summer months results in higher nonutility power generation revenue being generated from the Homer City facilities and the Illinois plants. By contrast, the First Hydro plants and Contact Energy have higher nonutility power generation revenue during their winter months.

Financial services and other revenue decreased in 2002, primarily from Edison Capital's recording the cumulative impact of a change in its effective state tax rate on leveraged leases (that was substantially offset by tax benefits), a decrease in earning assets, no significant asset sales in 2002, and the impact of adopting the equity method of accounting in conformance with the infrastructure funds accounting policies. The decrease was also a result of the termination of a major contract at a nonutility subsidiary providing operation and maintenance services and another subsidiary's sale of nonutility real estate in 2001. Financial services and other revenue increased in 2001 primarily due to a subsidiary's sale of nonutility real estate and another subsidiary providing operating and maintenance services, primarily to power generators. Beginning in January 2001, a nonutility subsidiary began providing operation and maintenance services to independent power companies, some of which now own the generation stations SCE sold in 1998. From 1998 through December 2000, SCE provided these services for its previously owned generating stations.

Operating Expenses

Fuel expense increased for both 2002 and 2001. The increase in 2002 was primarily related to EME's consolidation of Contact Energy for a full year in 2002 as compared to a partial year in 2001, increased pumping power costs from EME's First Hydro plant, increased fuel costs from EME's Illinois plants and an increase at SCE related to a settlement agreement entered into with Peabody Western Coal Company associated with the Mohave Generating Station (Mohave). The increase was partially offset by decreased fuel costs from EME's Homer City facilities. The increase in 2001 was mainly due to EME's consolidation of Contact Energy for a partial year as compared to the equity method of accounting in 2000 and higher fuel costs at the First Hydro and Doga projects, partially offset by a decrease at EME's Illinois plants.

Purchased-power expense decreased in both 2002 and 2001. The 2002 decrease resulted primarily from lower expenses at SCE related to qualifying facilities (QFs), bilateral contracts and interutility contracts, as discussed below. In addition, the decrease reflects the absence of California Power Exchange (PX)/ Independent System Operator (ISO) purchased-power expense after mid-January 2001. PX/ISO purchased-power expense increased significantly between May 2000 and mid-January 2001, due to dramatic wholesale electricity price increases. In December 2000, the FERC eliminated the requirement that SCE buy and sell all power through the PX. Due to SCE's noncompliance with the PX's tariff requirement for posting collateral for all transactions, as a result of the downgrades in its credit rating, the PX suspended SCE's market trading privileges effective mid-January 2001. The 2001 decrease resulted from the absence of PX/ISO purchased-power expense after mid-January 2001, partially offset by increased expenses related to QFs, bilateral contracts and interutility contracts.

Federal law and CPUC orders required SCE to enter into contracts to purchase power from QFs at CPUC-mandated prices. These contracts expire on various dates through 2025. In 2002, purchased-power expense declined significantly, primarily due to lower payments to QFs. Generally, energy payments for gas-fired QFs are tied to spot natural gas prices. Effective May 2002, energy payments for renewable QFs were based on a fixed price of 5.37¢ per kWh. During 2002, spot natural gas prices were significantly lower than the same periods in 2001. The decrease in 2002 purchased-power expense related to bilateral contracts and interutility contracts was also due to the decrease in natural gas prices. In 2001, purchased-power expense related to QFs increased due to higher prices for natural gas. In early 2001, structural problems in the market caused abnormally high gas prices. The increase related to bilateral contracts was the result of SCE not having these contracts in 2000. The increase related to interutility contracts was volume-driven.

Provisions for regulatory adjustment clauses – net increased in 2002 and decreased in 2001. The 2002 increase was primarily due to the establishment of the PROACT regulatory asset in 2001, overcollections used to recover the PROACT balance and revenue collected to recover the rate reduction bond regulatory asset, partially offset by the impact of SCE's implementation of CPUC decisions related to URG and the PBR mechanism, as well as the impact of other regulatory actions. The 2001 decrease resulted from SCE recording the $3.6 billion PROACT regulatory asset in fourth quarter 2001.

As a result of the URG decision, SCE reestablished regulatory assets previously written off (approximately $1.1 billion) related to its nuclear plant investments, purchased-power settlements and flow-through taxes, and decreased the PROACT balance by $256 million, all retroactive to January 1, 2002. The impact of the

URG decision is reflected in the financial statements as a credit (decrease) to the provisions for regulatory adjustment clauses of $644 million, partially offset by an increase in deferred income tax expense of $164 million, for a net credit to earnings of $480 million (see "SCE's Regulatory Matters—URG Decision" discussion). As a result of the CPUC decision that modified the PBR mechanism, SCE recorded a $136 million credit (decrease) to the provisions for regulatory adjustment clauses in the second quarter of 2002, to reflect undercollections in CPUC-authorized revenue resulting from changes in retail rates (see "SCE's Regulatory Matters—PBR Decision" discussion).

Other operation and maintenance expense increased in both 2002 and 2001. The 2002 increase was primarily due to increases at both SCE and EME.

SCE's other operation and maintenance expense increase in 2002 primarily due to the San Onofre Unit 2 refueling outage in 2002, increases in transmission and distribution maintenance and inspection activities, and cost containment efforts that took place in 2001. The increases were partially offset by lower expenses related to balancing accounts.

EME's other operation and maintenance expense increased in 2002 mainly due to an increase in transmission costs, primarily due to consolidating Contact Energy, effective June 1, 2001 and an increase in operating leases due to the sale-leaseback transactions for the Homer City and Powerton-Joliet power facilities. There were no comparable lease costs for the Homer City facilities through the period ended December 2001 and the Powerton-Joliet power facilities through the period ended August 2000. See "Off-Balance Sheet Transactions—EME's Off-Balance Sheet Transactions—Sale-Leaseback Transactions," for discussion of the financial impact of sale-leaseback transactions; asset impairment and other charges in 2002 consisting of $61 million related to the write-off of capitalized costs associated with the termination of the turbines from Siemens Westinghouse, $45 million in settlement of the In-City Obligation (refer to "Other Developments—EME's Chicago In-City Obligation," for further discussion), and $25 million related to the write-off of capitalized costs associated with the suspension of the Powerton Station SCR major capital environmental improvements project at the Illinois plants. These increases were partially offset by a gain recorded related to the termination of postretirement benefits as discussed below.

The settlement of postretirement employee benefit liability relates to a retirement health care and other benefits plan for represented employees at the Illinois plants that expired on June 15, 2002. In October 2002, Midwest Generation reached an agreement with its union-represented employees on new benefits plans, which extend from January 1, 2003 through June 30, 2005. Midwest Generation continued to provide benefits at the same level as those in the expired agreement until December 31, 2002. The accounting for postretirement benefits liabilities has been determined on the basis of a substantive plan under an accounting standard for postretirement benefits other than pensions. A substantive plan means that Midwest Generation assumed, for accounting purposes, it would provide for postretirement health care benefits to union-represented employees following conclusion of negotiations to replace the current benefits agreement, even though Midwest Generation had no legal obligation to do so. Under the new agreement, postretirement health care benefits will not be provided. Accordingly, Midwest Generation treated this as a plan termination in accordance with this accounting standard and recorded a pre-tax gain of $71 million during the fourth quarter of 2002.

The 2001 increase of other operation and maintenance expense primarily resulted from increased plant operating expenses at EME's Illinois plants as a result of a sale-leaseback transaction, consolidation of Contact Energy due to EME's increased ownership, as well as increased expenses at a nonutility subsidiary related to the sale of real estate.

Depreciation, decommissioning and amortization expense increased in 2002 and decreased in 2001. The increase in 2002 was mainly due to an increase in depreciation expense associated with SCE's additions to transmission and distribution assets and an increase in SCE's nuclear decommissioning expense. A 1994 CPUC decision allowed SCE to accelerate the recovery of its nuclear-related assets while deferring the recovery of its distribution-related assets for the same amount. Beginning in January 2002, the CPUC approved the commencement of recovery of SCE's deferred distribution assets. In addition, the increases reflect amortization expense on the nuclear regulatory asset reestablished during second quarter 2002 based on the URG decision (discussed below). These increases were partially offset by lower depreciation expense at EME's Homer City facilities due to the sale-leaseback transaction that took place in December 2001, as well as ceasing the amortization of goodwill in January 1, 2002. The decrease in 2001 was primarily due to SCE's nuclear investment amortization expense ceasing because the unamortized nuclear investment regulatory asset was included in the December 31, 2000 write-off.

Other Income and Deductions

Interest and dividend income increased for both 2002 and 2001. The 2002 increase was mainly due to the interest income earned on the PROACT balance at SCE. The increase was partially offset by lower interest income due to lower average cash balances and lower interest rates at SCE, EME and Edison Capital during 2002, as compared to 2001 and lower earnings from Edison Capital's investments. The increase in 2001 was mainly due to an overall higher cash balance, as SCE conserved cash due to its liquidity crisis, as well as an increase at MEHC due to interest earned on funds placed into an escrow account from the sale of senior secured notes and a term loan.

Equity in income from partnerships and unconsolidated subsidiaries – net decreased in 2002 and increased in 2001. The 2002 decrease was primarily due to a decrease in EME's share of income from the Big 4 projects and Four Star Oil & Gas, partially offset by an increase in EME's share of income from the Paiton Energy and ISAB projects. The 2001 increase was primarily due to an increase in EME's share of income from the Big 4 projects and the ISAB projects. EME's third quarter equity income from its domestic energy projects is materially higher than equity income related to other quarters of the year due to warmer weather during the summer months and because a number of EME's domestic energy projects, located on the west coast, have power sales contracts that provide for higher payment during the summer months.

Other nonoperating income decreased for both 2002 and 2001. The 2002 decrease was primarily at EME, partially offset by increases at SCE and Edison Capital. The decrease at EME was mainly due to foreign exchange losses in 2002 compared to foreign exchange gains in 2001, lower gains on the sale of EME's interest in energy projects in 2002 compared to 2001, as well as a gain on early extinguishment of debt in 2001. The increase at SCE was primarily due to property condemnation settlements received at SCE, partially offset by PBR incentive awards for 1999 and 2000, which were approved by the CPUC and recorded in 2002. The increase at Edison Capital was primarily due to lower foreign exchange losses in 2002 compared to 2001. The 2001 decrease in other nonoperating income primarily reflects SCE's gains on sales of marketable securities in 2000.

Interest expense – net of amounts capitalized decreased in 2002 and increased in 2001. The 2002 decrease is mainly due to: lower long-term debt balances at Edison Capital as compared to 2001; lower short-term debt balances at Edison International (parent only) and all of the principal subsidiaries compared to 2001; and lower interest expense at SCE related to the suspension of payments for purchased power during 2001, which were subsequently paid in early 2002. The decrease was partially offset by: an increase in interest expense on long-term debt at SCE due to higher long-term debt balances; an increase in long-term debt interest expense at MEHC resulting from the debt financing that took place in July 2001; and the consolidation of Contact Energy at EME. The increase in 2001 reflects additional long-term debt at SCE, the issuance of new debt at MEHC (parent only), and higher short-term debt balances at both SCE and its parent company.

Other nonoperating deductions increased in 2002 and decreased in 2001. The 2002 increase was primarily due to a goodwill impairment charge at EME in 2002 resulting from the adoption of a new accounting standard for goodwill and other intangibles, partially offset by lower accruals for regulatory matters at SCE in 2002. The 2001 decrease was primarily due to lower accruals for regulatory matters at SCE in 2001.

Income Taxes

Income tax expense decreased in 2002 and increased in 2001. The decrease in 2002 was primarily due to a reduction in pre-tax income. Other decreases in tax expense resulted from: a reduction in state income tax, including a cumulative adjustment to deferred tax balances at Edison Capital to reflect changes in its effective state tax rate; favorable resolution of tax audits at SCE; and an increase in flow through property related items, net of the reestablishment of tax related regulatory assets upon implementation of the URG decision at SCE. The increase in 2001 reflects $1.5 billion in income tax expense related to the $3.6 billion (before tax) PROACT regulatory asset establishment in fourth quarter 2001. Absent the $1.5 billion income tax expense in 2001, Edison International's income taxes increased due to a higher pre-tax income.

Edison International's composite federal and state statutory rate was approximately 40.5% for all years presented. The lower effective tax rate of 25.6% realized in 2002 was primarily due to: the reestablishment of tax-related regulatory assets upon implementation of the URG decision at SCE; a favorable adjustment to Edison Capital's cumulative deferred taxes for changes in its effective state tax rate; benefits received from low-income housing credits at Edison Capital; favorable resolution of tax audits at SCE; and the effect of lower foreign tax rates and permanent reinvestments of earnings of foreign affiliates at EME. The decrease was partially offset by foreign losses that were unable to be utilized in 2002. The 2001 effective tax rate was comparable to the composite federal and state statutory tax rate.

Loss from Discontinued Operations

Edison International's discontinued operations in 2002 represent the one-time asset impairment charge of $77 million, after tax, resulting from EME's Lakeland project being placed into administrative receivership in the U.K., along with $22 million in 2002 operating results from the Lakeland project. See further discussion at "Discontinued Operations and Dispositions." The 2002 loss also includes minor adjustments related to the sale of EME's Fiddler's Ferry and Ferrybridge coal stations and the majority of Edison Enterprises subsidiaries in 2001. The 2001 loss includes impairment charges resulting from the sale of the Fiddler's Ferry and Ferrybridge plants and the majority of Edison Enterprises' (a nonutility subsidiary of Edison International that formerly provided retail services) assets, as well as operating results from the discontinued entities.

FINANCIAL CONDITION

The liquidity of Edison International is affected primarily by debt maturities, access to capital markets, dividend payments, capital expenditures, lease obligations, asset purchases and sales, investments in partnerships and unconsolidated subsidiaries, credit ratings, utility regulation and energy market conditions. Capital resources primarily consist of cash from operations, asset sales and external financings. California law prohibits SCE from incurring or guaranteeing debt for its nonutility affiliates.

The parent company's short-term and long-term debt has been used for general corporate purposes, including investments in its subsidiaries' business activities. The parent company currently has no short-term debt outstanding. SCE's short-term debt is normally used to finance procurement-related obligations. Long-term debt is used mainly to finance the utility's rate base. EME's short-term and long-term debt was used to finance acquisitions and development and is currently used for general corporate purposes. MEHC's long-term debt was used to retire some of Edison International's debt. Edison Capital's short-term and long-term debt has been used for general corporate purposes, as well as investments. External financings are influenced by market conditions and other factors.

The "Financial Conditions" section of this MD&A discusses cash flows from operating, financing and investing activities, and liquidity issues at Edison International (parent only), SCE, MEHC, EME and Edison Capital.

Cash Flows from Operating Activities

Net cash provided (used) by operating activities:

In millions Year ended December 31,	**2002**	2001	2000
Continuing operations	**$ 2,247**	$ 3,121	$ 1,385
Discontinued operations	**80**	(147)	19
	$ 2,327	$ 2,974	$ 1,404

The 2002 decrease in cash provided by operating activities from continuing operations was mainly due to SCE's March 2002 repayment of past-due obligations, partially offset by higher overcollections used to recover regulatory assets resulting from the CPUC-approved surcharges (1¢ per kWh in January 2001 and 3¢ per kWh in June 2001) and an increase in operating cash flow from EME resulting from the timing of cash payments related to working capital items. The 2001 increase in cash provided by operating activities from continuing operations was primarily due to SCE suspending payments for purchased power and other obligations beginning in January 2001. Cash provided by continuing operations also reflects the CPUC-approved surcharges that SCE billed in 2001, partially offset by lower operating cash flow from EME from timing of cash receipts and payments related to working capital items.

Cash provided by operating activities from discontinued operations in 2002 primarily reflects the settlement of working capital items from EME's Fiddler's Ferry and Ferrybridge power plants and operating income from the EME's Lakeland power plant during 2002. Cash used by operating activities from discontinued operations in 2001 reflects operating losses from the Ferrybridge and Fiddler's Ferry power plants in 2001, as compared to operating income in 2000, and the timing of cash payments related to working capital items.

Cash Flows from Financing Activities

Net cash provided (used) by financing activities:

In millions Year ended December 31,	**2002**	2001	2000
Continuing operations	**$ (2,582)**	$ (379)	$ 535
Discontinued operations	**(19)**	(1,178)	223
	$ (2,601)	$ (1,557)	$ 758

Cash used by financing activities from continuing operations in 2002 mainly consisted of long-term and short-term debt payments at SCE and EME.

During the first quarter of 2002, SCE paid $531 million of matured commercial paper and remarketed $196 million of the $550 million of pollution-control bonds repurchased during December 2000 and early 2001. Also during the first quarter of 2002, SCE replaced the $1.65 billion credit facility with a $1.6 billion financing and made a payment of $50 million to retire the entire credit facility. Throughout the year, SCE paid approximately $1.2 billion of maturing long-term debt. The $1.6 billion financing included a $600 million, one-year term loan due March 3, 2003. SCE prepaid $300 million of this loan in August 2002 and prepaid the balance on February 11, 2003. EME's debt payments in 2002 consisted of payment of $100 million of senior notes that matured in 2002, net payments of $80 million on EME's $487 million corporate credit facility, $44 million related to debt service payments and payments of $86 million on EME's debentures and notes. Edison Capital's net payments on short-term debt were approximately $312 million.

Cash used by financing activities from continuing operations in 2001 consisted of long-term debt repayments at EME and short-term debt repayments at the parent company and at EME. The uses of cash were partially offset by the issuance of long-term debt at EME of $1.0 billion and at MEHC of $1.2 billion.

Cash used by financing activities from discontinued operations in 2002 represents repayments of long-term debt from EME's Lakeland power plant. Cash used by financing activities from discontinued operation in 2001 related to the early repayment of the term loan facility in connection with the sale of the Ferrybridge and Fiddler's Ferry power plants on December 21, 2001.

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 electric industry restructuring legislation and a financing order of the CPUC and consists generally of the right to be paid a specified amount from nonbypassable rates charged to residential and small commercial customers. The rate reduction notes are being repaid over 10 years through these nonbypassable residential and small commercial customer rates, which constitute the transition property purchased by SCE Funding LLC. The remaining series of outstanding rate reduction notes have scheduled maturities through 2007, with interest rates ranging from 6.22% to 6.42%. The notes are collateralized by the transition property and are not collateralized by, or payable from, assets of SCE or Edison International. SCE used the proceeds from the sale of the transition property to retire debt and equity securities. Although, as required by accounting principles generally accepted in the United States, 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.

Cash Flows from Investing Activities

Net cash provided (used) by investing activities:

In millions Year ended December 31,	**2002**	2001	2000
Continuing operations	**$ (1,331)**	$ (424)	$ (576)
Discontinued operations	**2**	1,125	(89)
	$ (1,329)	$ 701	$ (665)

Cash flows from investing activities are affected by additions to property and plant, EME's sales of assets and SCE's funding of nuclear decommissioning trusts.

SCE's additions to property and plant were approximately $1.0 billion, primarily for transmission and distribution assets; EME's capital additions of $554 million in 2002 included a $300 million payment for the Illinois peaker power units that were subject to a lease (see "Off-Balance Sheet Transactions—EME's Off-Balance Sheet Transactions"). The remaining increases were primarily for the Valley Power Peaker project in Australia, the Illinois plants, the Homer City facilities and payments related to three turbines. These increases were partially offset by proceeds from the sale of various EME projects.

Cash flows from investing activities from continuing operations in 2001 included proceeds from EME's sale-leaseback transaction with respect to the Homer City facilities in December 2001 and from EME's sale of a 50% interest in the Sunrise project, as well as EME's equity contributions to meet capital calls by its QF partnerships in California. In 2001, EME also acquired 50% interest in the CBK project and purchased additional shares in Contact Energy.

In 2001, cash provided by investing activities from discontinued operations was primarily due to the net proceeds of £643 million (approximately $945 million at December 31, 2001) received from the sale of the Ferrybridge and Fiddler's Ferry power plants on December 21, 2001.

Decommissioning costs are recovered in utility 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, non-dollar, 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 CPUC review proceeding will provide input into future contributions. SCE's costs to decommission San Onofre Unit 1 are paid from the nuclear decommissioning trust funds. These withdrawals from the decommissioning trusts are netted with the contributions to the trust funds in the Consolidated Statements of Cash Flows.

Edison International's (parent only) Liquidity Issues

The parent company's liquidity and its ability to pay interest, debt principal, operating expenses and dividends to common shareholders are affected by dividends from subsidiaries, tax-allocation payments under its tax allocation agreement with its subsidiaries, and capital raising activities.

The CPUC regulates SCE's capital structure by requiring that SCE maintain a prescribed percentage of equity in the utility capital structure. SCE may not make any distributions to Edison International that would reduce the equity component of SCE's capital structure below the prescribed level. SCE's settlement agreement with the CPUC also precludes SCE from declaring or paying dividends or other distributions on its common stock (all of which is held by its parent, Edison International) prior to the earlier of the date on which SCE has recovered all of its procurement-related obligations or January 1, 2005, except that if SCE has not recovered all of its procurement-related obligations by December 31, 2003, SCE may apply to the CPUC for consent to resume common stock dividends prior to January 1, 2005 and the CPUC will not unreasonably withhold its consent. Material factors affecting the timing of recovery of the PROACT balance are discussed below in "SCE's Regulatory Matters—PROACT Regulatory Asset and —CPUC Litigation Settlement Agreement." In addition, see "—SCE's Liquidity Issues" for further discussion of factors affecting the ability of SCE to make dividend payments.

Edison Capital's ability to make dividend payments is restricted by debt covenants, which require Edison Capital to maintain a specified minimum net worth. Edison Capital currently exceeds the threshold amount.

Currently, MEHC is permitted to pay dividends under the terms of its outstanding debt (a) in amounts sufficient to permit Edison International to make required interest payments on its outstanding 6-7/8% notes due 2004, (b) to pay Edison International corporate overhead in amounts consistent with historically expended amounts, and (c) for other Edison International working capital and general corporate purposes in an amount not to exceed $50 million. After July 15, 2003, MEHC may not pay dividends unless it has an interest coverage ratio of 2.0x. At December 31, 2002, its interest coverage ratio was 1.51x. See "—MEHC's Liquidity Issues—MEHC's Interest Coverage Ratio." MEHC did not declare or pay a dividend in 2002. MEHC's ability to pay dividends is dependent on EME's ability to pay dividends to MEHC.

EME and its subsidiaries have certain dividend restrictions as discussed in "—EME's Liquidity Issues" section below. EME did not pay or declare a dividend during 2002.

The ability of Edison International to pay its 6-7/8% notes due September 2004 may be substantially dependent, among other things, on subsidiary dividends.

As further discussed in "Current Developments—MEHC and EME Developments," a subsidiary of EME has $911 million of debt maturing in December 2003, which will need to be repaid, extended or refinanced. There is no assurance that EME will be able to repay, extend or refinance the Edison Mission Midwest Holdings debt obligation on similar terms and rates as the existing debt, on commercially reasonable terms, on the terms permitted under the MECH financing documents or at all. The independent accountants' audit opinions for MEHC, EME and Midwest Generation contain an explanatory paragraph that indicates the consolidated financial statements are prepared on the basis that these companies will continue as a going concern. This obligation would raise substantial doubt about their ability to continue as a going concern. Edison International's investment in MEHC, through a wholly owned subsidiary, as of December 31, 2002, was $953 million. MEHC's investment in EME, as of December 31, 2002, was $1.9 billion.

In May 2001, Edison International deferred the interest payments in accordance with the terms of its outstanding $825 million quarterly income debt securities, due 2029, issued to an affiliate. This caused a corresponding deferral of distributions on quarterly income preferred securities issued by that affiliate. Interest payments may be deferred for up to 20 consecutive quarters, at a time. Edison International cannot pay cash dividends on or purchase its common stock as long as interest is being deferred.

In March 2002, Edison International received cash, primarily due to an Internal Revenue Service (IRS) refund resulting from a March 2002 change in federal tax law and, as a result, paid in full a $250 million note due to SCE related to tax-allocation payments owed to SCE for the year 2000. Edison International received $152 million in tax-allocation payments during 2002. At December 31, 2002, the parent company had $252 million of cash on hand. In early 2003, Edison International repurchased $132 million of its outstanding $750 million in notes due 2004.

SCE's Liquidity Issues

SCE expects to meet its continuing obligations in 2003 from cash on hand, which was $1.0 billion at December 31, 2002, and operating cash flows.

Sustained high wholesale energy prices from May 2000 through June 2001 and a delay by the CPUC in passing those costs on to ratepayers resulted in significant undercollections of wholesale power costs. These undercollections, 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, materially and adversely affected SCE's liquidity throughout 2001. As a result of its liquidity concerns, beginning in January 2001, SCE suspended payments for purchased power, deferred payments on outstanding debt, and did not declare or pay dividends on any of its cumulative preferred stock or common stock.

In January 2002, the CPUC adopted a resolution implementing a settlement agreement with SCE. Based on the rights to power procurement cost recovery and revenue established by the agreement and the PROACT resolution, SCE repaid its undisputed past-due obligations and near-term debt maturities in March 2002, using cash on hand resulting from rate increases approved by the CPUC in 2001 and the proceeds of $1.6 billion in senior secured credit facilities and the remarketing of $196 million in pollution-control bonds. The $1.6 billion financing included a $600 million, one-year term loan due on March 3, 2003. SCE prepaid $300 million of this loan on August 14, 2002 and the remaining $300 million on February 11, 2003. The $1.6 billion financing also included a $300 million line of credit, which is fully drawn and expires March 2004, and a $700 million term loan with a March 2005 final maturity. Under the term loan, net cash proceeds for the issuance of capital stock or new indebtedness must be used to reduce the term loan subject to certain exceptions.

On February 24, 2003, SCE completed an exchange offer for its 8.95% variable rate notes due November 2003. A total of $966 million of these notes were exchanged for $966 million of a new series of first and refunding mortgage bonds due February 2007. As a result of the exchange offer and the $300 million payment on February 11, 2003, SCE's remaining significant debt maturities in 2003 are approximately $159 million, comprising $34 million of the 8.95% variable rate notes due November 2003 that were not exchanged and $125 million in first and refunding mortgage bonds due June 2003. In addition, approximately $250 million of rate reduction notes are due throughout 2003. These notes have a separate cost recovery mechanism approved by state legislation and CPUC decisions.

SCE currently expects to recover the PROACT balance in mid-2003. Material factors affecting the timing of recovery of the PROACT balance are discussed in "SCE's Regulatory Matters—PROACT Regulatory Asset." As of December 31, 2002, SCE's common equity to total capitalization ratio, for rate-making purposes, was approximately 62%. This is substantially greater than the CPUC-authorized level of 48%. SCE's settlement agreement with the CPUC provides that the CPUC will not impose any penalty on SCE for noncompliance with the authorized capital structure during the PROACT recovery period. SCE

A discussion of each market area is set forth below.

Illinois Plants

Electric power generated at the Illinois plants is currently sold under three power purchase agreements between EME's wholly owned subsidiary, Midwest Generation, and Exelon Generation Company, under which Exelon Generation purchases capacity and has the right to purchase energy generated by the Illinois plants. The agreements, which began on December 15, 1999 and have a term of up to five years, provide for capacity and energy payments. Exelon Generation is obligated to make a capacity payment for the plants under contract and an energy payment for the electricity produced by these plants and taken by Exelon Generation. The capacity payments provide the revenue for fixed charges, and the energy payments compensate the Illinois plants for variable costs of production.

Virtually all of the energy and capacity sales from the Illinois plants in 2002 were to Exelon Generation under the power purchase agreements. Under each of the power purchase agreements, Exelon Generation, upon notice by a given date, has the option to terminate each agreement with respect to all or a portion of the units subject to it.

In July 2002, under the power purchase agreement related to Midwest Generation's coal-fired generation units, Exelon Generation exercised its option to purchase 1,265 MW of capacity and energy during 2003 (of a possible total of 3,949 MW subject to option) from the option coal units. As a result, 2,684 MW of capacity of the Will County 1 and 2, Joliet 6 and 7, and Powerton 5 and 6 units ceased to be subject to the power purchase agreement from and after January 1, 2003. Exelon Generation continues to have a similar option, exercisable not later than 180 days prior to January 1, 2004, to retain or release for 2004 all or a portion of the option coal units retained for 2003. Exelon Generation remains committed to purchase the capacity of certain committed units having 1,696 MW of capacity for both 2003 and 2004.

In October 2002, under the power purchase agreements related to Midwest Generation's Collins Station and peaking units, Exelon Generation exercised its option to terminate the existing power purchase agreements during 2003 with respect to (a) 1,614 MW of capacity and energy (of a possible total of 2,698 MW subject to the option to terminate) from the Collins Station, a natural gas and oil-fired electric generating station, and (b) 113 MW of capacity and energy (of a possible total of 807 MW subject to the option to terminate) from the natural gas and oil-fired peaking units, in accordance with the terms of each applicable power purchase agreement. As a result, 1,614 MW of capacity from the Collins Units 2, 4 and 5, and 113 MW of capacity from the Lombard 33 and Calumet 33 and 34 peaking units, ceased to be subject to a power purchase agreement from and after January 1, 2003. Previously, Exelon Generation exercised its option to terminate 137 MW of capacity from the Bloom and Waukegan peaking units effective January 1, 2002. Exelon Generation continues to have a similar option to terminate, exercisable not later than 90 days prior to January 1, 2004, the power purchase agreements for 2004 with respect to all or a portion of the Collins Station and peaking units not previously terminated for 2003 (1,084 MW from the Collins Station and 694 MW from the peaking units).

The energy and capacity from any units which are not subject to one of the power purchase agreements with Exelon Generation will be sold under terms, including price and quantity, to be negotiated with customers through a combination of bilateral agreements, forward energy sales and spot market sales. Thus, EME will be subject to market risks related to the price of energy and capacity described above. EME expects that capacity prices for merchant energy sales will, in the near term, be substantially lower than those Midwest Generation currently receives under its existing agreements with Exelon Generation (with the possibility of minimal revenue due to the current oversupply conditions in this marketplace). EME further expects that the lower revenue resulting from this difference will be offset in part by energy prices, which EME believes will, in the near term, be higher for merchant energy sales than those Midwest Generation currently receives under its existing agreements, as indicated below in the table of forward-looking prices. EME intends to manage this price risk, in part, by accessing both the wholesale customer and over-the-counter markets described below as well as using derivative financial instruments in accordance with established policies and procedures.

During 2003, the primary markets available to Midwest Generation for wholesale sales of electricity from the Illinois plants are expected to be wholesale customer and over-the-counter. The most liquid over-the-counter markets in the Midwest region are sales into the control area of Cinergy, referred to as Into Cinergy, and, to a lesser extent, sales into the control area of Commonwealth Edison, referred to as Into ComEd. Into Cinergy and Into ComEd are bilateral markets for the sale or purchase of electrical energy for future delivery. Performance of transactions in these markets is subject to contracts that generally provide for liquidated damages supported by a variety of credit requirements, which may include independent credit assessment, parental guarantees, and letters of credit and cash margining arrangements.

The following table sets forth the forward month-end market prices for energy per megawatt-hour for the calendar 2003 and calendar 2004 strips (defined as energy purchases for the entire calendar year) as publicly quoted for sales Into ComEd and Into Cinergy during 2002. These forward prices will continue to fluctuate as a result of a number of factors, including gas prices, electricity demand, which is also affected by economic growth, and the amount of existing and planned power plant capacity. The actual spot prices for electricity delivered into these markets may vary materially from the forward market prices.

	Into ComEd*					
	2003			2004		
Date	On-Peak	Off-Peak	24-Hr	On-Peak	Off-Peak	24-Hr
January 31, 2002	$ 27.26	$ 18.34	$ 22.56	$ 28.72	$ 19.09	$ 23.65
February 28, 2002	28.96	18.50	23.48	31.30	19.25	24.99
March 31, 2002	32.50	19.85	25.56	34.31	21.35	27.20
April 30, 2002	32.55	19.05	25.65	33.55	20.05	26.65
May 31, 2002	30.85	17.31	23.71	32.30	19.18	25.38
June 30, 2002	29.54	16.88	22.50	30.98	19.38	24.53
July 31, 2002	28.64	16.90	22.37	30.09	18.90	24.11
August 30, 2002	28.75	17.00	22.47	30.20	19.25	24.34
September 30, 2002	29.16	15.92	22.09	30.61	18.17	23.96
October 31, 2002	29.01	15.62	21.85	30.46	17.62	23.59
November 27, 2002	29.11	15.32	21.74	31.38	17.32	23.86
December 31, 2002	29.98	15.58	22.29	32.25	18.14	24.71

	Into Cinergy**					
	2003			2004		
Date	On-Peak	Off-Peak	24-Hr	On-Peak	Off-Peak	24-Hr
January 31, 2002	$ 28.38	$ 18.77	$ 23.32	$ 29.85	$ 19.52	$ 24.41
February 28, 2002	30.30	18.75	24.25	32.64	19.50	25.75
March 31, 2002	33.82	20.15	26.33	35.63	21.65	27.97
April 30, 2002	34.03	19.75	26.73	35.03	20.75	27.73
May 31, 2002	31.74	18.88	24.96	33.97	20.75	27.00
June 30, 2002	31.08	18.25	23.95	32.50	20.75	25.97
July 31, 2002	29.34	18.25	23.41	32.00	20.25	25.72
August 30, 2002	29.63	18.00	23.41	31.60	20.25	25.54
September 30, 2002	30.56	17.50	23.59	32.18	19.75	25.54
October 31, 2002	30.64	17.14	23.43	32.35	19.14	25.30
November 27, 2002	30.59	17.02	23.35	32.00	19.02	25.07
December 31, 2002	31.73	16.69	23.70	32.88	19.25	25.60

(1) On-peak refers to the hours of the day between 7:00 a.m. and 11:00 p.m. Monday through Friday. All other hours of the week are referred to as off-peak.

* Source: Prices were obtained by gathering publicly available broker quotes and adjusted for historical basis differences between ComEd and Cinergy.

** Source: Prices were obtained by gathering publicly available broker quotes.

The average price that EME derives from electricity sales is normally higher than a 24-hour price as it manages its generation to optimize on-peak periods when power prices are higher.

Midwest Generation intends to hedge a portion of its merchant portfolio risk. To the extent it does not do so, the unhedged portion will be subject to the risks and benefits of spot-market price movements. The extent to which Midwest Generation will hedge its market price risk through forward over-the-counter sales depends on several factors. First, Midwest Generation will evaluate over-the-counter market prices to determine whether sales at forward market prices are sufficiently attractive compared to assuming the risk associated with spot market sales. Second, Midwest Generation's ability to enter into hedging transactions will depend upon Midwest Generation's and its affiliate's liquidity and upon the over-the-counter forward sales markets' having sufficient liquidity to enable Midwest Generation to identify counterparties who are able and willing to enter into hedging transactions with Midwest Generation. Due to factors beyond Midwest Generation's control, market liquidity decreased significantly during 2002, and a number of formerly significant trading parties have completely withdrawn from the market or substantially reduced their trading activities. See "—Credit Risks."

In addition to the prevailing market prices, the ability of Midwest Generation to derive profits from the sale of electricity from the released units will be affected by the cost of production, including costs incurred to comply with environmental regulations. The costs of production of the released units vary and, accordingly, depending on market conditions, the amount of generation that will be sold from the released units is expected to vary from unit to unit. In this regard, Midwest Generation suspended operations of Units 1 and 2 at its Will County plant and Units 4 and 5 at its Collins Station at the end of 2002 pending improvement in market conditions. If market conditions were to be depressed for an extended period of time, Midwest Generation would need to consider decommissioning these units, which would result in a charge against income.

Midwest Generation's ability to transmit energy to counterparty delivery points to consummate spot sales and hedging transactions may be affected by transmission service limitations and constraints and new standard market design proposals proposed by and currently pending before the FERC. Although the FERC and the relevant industry participants are working to minimize such issues, Midwest Generation cannot determine how quickly or how effectively such issues will be resolved.

Homer City Facilities

Electric power generated at the Homer City facilities is sold under bilateral arrangements with domestic utilities and power marketers under short-term contracts with terms of two years or less, or to the PJM or the NYISO. These pools have short-term markets, which establish an hourly clearing price. The Homer City facilities are situated in the PJM control area and are physically connected to high-voltage transmission lines serving both the PJM and NYISO markets. The Homer City facilities can also transmit power to the Midwestern United States.

The following table depicts the average market prices per megawatt-hour in PJM during the past three years:

	24-Hour PJM Historical Energy Prices*		
	2002	2001	2000
January	$ 20.52	$ 36.66	$ 23.15
February	20.62	29.53	23.84
March	24.27	35.05	21.97
April	25.68	34.58	23.79
May	21.98	28.64	28.41
June	24.98	26.61	23.06
July	30.01	30.21	23.53
August	30.40	43.99	29.01
September	29.00	22.44	25.12
October	27.64	21.95	29.20
November	25.18	19.58	30.68
December	27.33	19.66	44.63
Yearly Average	$ 25.63	$ 29.07	$ 27.20

* Energy prices were calculated at the Homer City busbar (delivery point) using historical hourly prices provided on the PJM-ISO web-site.

As shown in the above table, the average historical market prices at the Homer City busbar (delivery point) during 2002 are below the average historical market prices during 2001. Forward market prices in PJM fluctuate as a result of a number of factors, including natural gas prices, transmission congestion, changes in market rules, electricity demand, which is affected by weather and economic growth, and the amount of existing and planned power plant capacity. The actual spot prices for electricity delivered into these markets may vary materially from the forward market prices.

The following table sets forth the forward month-end market prices for energy per megawatt-hour for the calendar 2003 and calendar 2004 strips, which are defined as energy purchases for the entire calendar year, for sales in PJM during 2002:

	24-Hour PJM Forward Energy Prices*	
	2003	2004
January 31, 2002	$ 25.48	$ 26.31
February 28, 2002	27.11	27.59
March 31, 2002	29.69	29.66
April 30, 2002	29.19	28.81
May 31, 2002	28.40	28.24
June 30, 2002	27.96	28.09
July 31, 2002	27.94	28.43
August 30, 2002	28.10	28.17
September 30, 2002	29.00	28.99
October 31, 2002	29.11	29.17
November 27, 2002	29.67	29.24
December 31, 2002	31.87	30.18

* Energy prices were obtained by gathering publicly available broker quotes at PJM West (delivery point).

The forward prices at PJM West (an index of multiple delivery points) are generally higher than the prices of the Homer City busbar (delivery point) due to transmission congestion charges. The average PJM West price has been 5% higher than the average Homer City busbar price during the past 24 months. The average price that the Homer City facilities derive from electricity sales is normally higher than the

24-hour price as EME manages its generation to optimize the on-peak periods when power prices are higher.

The ability of EME's subsidiary, EME Homer City, to make payments under the long-term lease entered into as part of the sale-leaseback transaction discussed under "Off-Balance Sheet Transactions—EME's Off-Balance Sheet Transactions—Sale-Leaseback Transactions," depends on revenue generated by the Homer City facilities, which depend in part on the market conditions for the sale of capacity and energy. These market conditions are beyond EME's control.

United Kingdom

Since 1989, EME's plants in the U.K. have sold their electrical energy and capacity through a centralized electricity pool, which established a half-hourly clearing price, also referred to as the pool price, for electrical energy. On March 27, 2001, this system was replaced by the U.K. government with a bilateral physical trading system referred to as the new electricity trading arrangements. The First Hydro plant has entered into forward contracts of varying terms that expire on various dates through August 2005.

The new electricity trading arrangements provide for, among other things, the establishment of a range of voluntary short-term power exchanges and brokered markets operating from a year or more in advance to 1 hour prior to a trading period of one-half hour; 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. The grid operator retains the right under the new market mechanisms to purchase system reserve and response services to maintain the quality of the electrical supply directly from generators (generally referred to as ancillary services). Ancillary services contracts typically run for a year and can consist of both fixed amounts and variable amounts represented by prices for services that are only paid for when actually called upon by the grid operator. Physical bilateral contracts have replaced the prior financial contracts for differences, but have a similar commercial function. A key feature of the new arrangements is to require firm physical delivery, which means that a generator must deliver, and a consumer must take delivery of, its net contracted positions or pay for any energy imbalance at highly volatile imbalance prices calculated by the market operator. A consequence of this new system has been to increase greatly the motivation of parties to contract in advance and to further develop forwards and futures markets of greater liquidity than at present. Furthermore, another consequence of the market change is that counterparties may require additional credit support, including parent company guarantees or letters of credit.

The legislation introducing the new trading arrangements set a principal objective for the Gas and Electric Market Authority to "protect the interests of consumers...where appropriate by promoting competition...." This represents a shift in emphasis toward the consumer interest. However, this is qualified by a recognition that license holders should be able to finance their activities. The Utilities Act of 2000 also contains new powers for the Secretary of State to issue guidance to the Gas and Electric Market Authority on social and environmental matters, changes to the procedures for modifying licenses and a new power for the Gas and Electric Market Authority to impose financial penalties on companies for breach of license conditions. EME is monitoring the operation of these new provisions.

Following the introduction of the new trading arrangements in 2001, there has been a significant reduction in the wholesale price of electricity driven principally by surplus generating capacity. In addition, First Hydro was adversely affected in the second half of 2001 by a fall in the differential of the peak day time energy price compared to the cost of purchasing power at night time to pump water back to the top reservoir. This was a reflection of both excess generating capacity on the United Kingdom system as a whole and of the practice of generators holding plants on the system at part load to protect themselves against being out of balance in the new market. During 2002, there was further downward pressure on wholesale prices but some recovery in the peak/off peak differentials during the winter period.

Despite the difficult market conditions, First Hydro has continued to meet the interest coverage ratios specified in its bond financing documents and to meet its half yearly interest payments without recourse to the project's debt service reserve. EME believes that if market and trading conditions experienced in

2002 are sustained, First Hydro will continue to be compliant with the requirements of its bond financing documents. This compliance is, however, subject to market conditions for electric energy and ancillary services which are beyond EME's control.

Australia

The Loy Yang B plant and the Valley Power Peaker project sell 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 exposure to price volatility of the electricity traded into the pool, the Loy Yang B plant and the Valley Power Peaker project have entered into a number of financial hedges. The State Hedge agreement 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 of Victoria, Australia guarantees the State Electricity Commission of Victoria's obligations under the State Hedge. From January 2001 to July 2014, approximately 77% of the Loy Yang B plant output sold is hedged under the State Hedge. From August 2014 to October 2016, approximately 56% of the Loy Yang B plant output sold is hedged under the State Hedge. Additionally, the Loy Yang B plant and the Valley Power Peaker project have entered into a number of derivative contracts to mitigate further against price volatility inherent in the electricity pool. These contracts consist of fixed forward electricity contracts and/or cap contracts that expire on various dates through December 31, 2006.

New Zealand

A substantial portion of Contact Energy's generation output is hedged by sales to retail electricity customers and forward contracts with other wholesale electricity counterparties. Contact Energy has entered into forward contracts and/or option contracts of varying terms that expire on various dates through March 31, 2007. The New Zealand Government commissioned an inquiry into the electricity industry in February 2000. Following the inquiry report, the New Zealand Government released a Government Policy Statement at the center of which was a call for the industry to rationalize the three existing industry codes, form a single governance structure and address transmission pricing methodology. The Government Policy Statement also requested a model use of system agreement be developed, that is, a framework by which the retailers contract for services from each of the distribution networks, and a consumer complaints ombudsman be established. An essential theme throughout the Government Policy Statement was the desire that the industry retain a private multilateral self-governing structure. During 2001, an amendment to the Electricity Act of 1992 was passed that laid out the form that regulation would take if the industry does not heed the Government's call. A draft single governance code was put forward to the New Zealand Commerce Commission for approval early in 2002. In October 2002, the Commerce Commission approved the new arrangements in the form of a rulebook for the self-governance of the electricity sector. The Commission conditioned this authorization upon:

- changes to the governance arrangements to ensure that pro-competitive and public benefit enhancing rule changes are not delayed unduly in working groups;
- changes to the governance arrangements to allow the Electricity Governance Board discretion to override an industry vote opposing a pro-competitive and public benefit enhancing rule change;
- completion of the drafting of rules dealing with consumer issues; and
- a review of the efficacy of the part of the rulebook dealing with transmission services after two years.

The authorization will expire four years from the date of the implementation of the rulebook or on March 31, 2007, whichever is earlier.

Credit Risks

In conducting EME's price risk management and trading activities, EME contracts with a number of utilities, energy companies and financial institutions. Due to factors beyond EME's control, market liquidity has decreased significantly since the beginning of 2002 and a number of formerly significant trading parties have completely withdrawn from the market or substantially reduced their trading activities. The reduction in the credit quality of traditional trading parties increases EME's credit risk. In addition, the decrease in market liquidity may require EME to rely more heavily on wholesale electricity sales to wholesale customer markets, which may increase EME's credit risk. While various industry groups and regulatory agencies have taken steps to address market liquidity, transparency and credit issues, there is no assurance as to when, or how effectively, such efforts will restore market confidence. In the event a counterparty were to default on its trade obligation, EME would be exposed to the risk of possible loss associated with reselling the contracted product at a lower price if the non-performing counterparty were unable to pay the resulting liquidated damages owed to EME. Further, EME would be exposed to the risk of non-payment of accounts receivable accrued for products delivered prior to the time such counterparty defaulted.

To manage credit risk, EME looks at the risk of a potential default by its counterparties. Credit risk is measured by the loss EME would record if its counterparties failed to perform pursuant to the terms of their contractual obligations. EME has established controls to determine and monitor the creditworthiness of counterparties and uses master netting agreements whenever possible to mitigate its exposure to counterparty risk. EME may require counterparties to pledge collateral when deemed necessary. EME tries to manage the credit in the portfolio based on credit ratings using published ratings of counterparties and other publicly disclosed information, such as financial statements, regulatory filings, and press releases, to guide it in the process of setting credit levels, risk limits and contractual arrangements including master netting agreements. The credit quality of EME's counterparties is reviewed regularly by EME's risk management committee. In addition to continuously monitoring its credit exposure to its counterparties, EME also takes appropriate steps to limit or lower credit exposure. Despite this, there can be no assurance that EME's actions to mitigate risk will be wholly successful or that collateral pledged will be adequate.

EME measures credit risk exposure from counterparties of its merchant energy activities by the sum of: (i) 60 days of accounts receivable, (ii) current fair value of open positions, and (iii) a credit value at risk. EME's subsidiaries enter into master agreements and other arrangements in conducting price risk management and trading activities which typically provide for a right of setoff in the event of bankruptcy or default by the counterparty. Accordingly, EME's credit risk exposure from counterparties is based on net exposure under these agreements. The S&P credit ratings of EME's counterparties were as follows:

In millions	December 31, 2002
A or higher	$ 45
A–	37
BBB+	24
BBB	27
BBB–	2
Below investment grade	2
Total	$ 137

Exelon Generation accounted for 40%, 42% and 48% of nonutility power generation revenue in 2002, 2001 and 2000, respectively. EME expects the percentage to be less in 2003 because a smaller number of plants will be subject to contracts with Exelon Generation. See "Market Risk Exposures—EME's Market Risks—Commodity Price Risk—Illinois Plants." Any failure of Exelon Generation to make payments to Midwest Generation under the power purchase agreements could result in a shortfall of cash available for Midwest Generation to meet its obligations. A default by Midwest Generation in meeting its obligations could in turn have a material adverse affect on EME.

EME's contracted power plants and the plants owned by unconsolidated affiliates, in which EME owns an interest, sell power under long-term power purchase agreements. Generally, each plant sells its output to one counterparty. Accordingly, a default by a counterparty under a long-term power purchase agreement, including a default as a result of a bankruptcy, would likely have a material adverse affect on the operations of such power plant. During 2002, the counterparty to the Lakeland project power purchase agreement filed a notice of disclaimer of its power purchase agreement with the project, ultimately resulting in an impairment of $77 million, after tax. See "Discontinued Operations and

Dispositions." The Big 4 projects sell power to SCE, which is currently non-investment grade. SCE was adversely affected by the California energy crisis and during that time defaulted on its long-term power purchase agreements with each of the Big 4 projects. It has since repaid the past due amounts, with interest. If SCE again defaults on its long-term power purchase agreements with each of the Big 4 projects, it would have a material adverse effect on the related project.

Interest Rate Risk

Interest rate changes affect the cost of capital needed to operate EME's projects and the lease costs under the Collins Station Lease. EME has mitigated the risk of interest rate fluctuations by arranging for fixed rate financing or variable rate financing with interest rate swaps, interest rate options or other hedging mechanisms for a number of its project financings. Interest expense included $34 million, $17 million and $15 million of additional interest expense for the years 2002, 2001 and 2000, respectively, as a result of interest rate hedging mechanisms. EME has entered into several interest rate swap agreements under which the maturity date of the swaps occurs prior to the final maturity of the underlying debt. A 10% increase in market interest rates at December 31, 2002 would result in a $9 million increase in the fair value of EME's interest rate hedge agreements. A 10% decrease in market interest rates at December 31, 2002 would result in a $10 million decrease in the fair value of EME's interest rate hedge agreements. Based on the amount of variable rate long-term debt for which EME has not entered into interest rate hedge agreements and the amount of the Collins lease at December 31, 2002, a 100 basis point change in interest rates at December 31, 2002 would increase or decrease 2003 income before taxes by approximately $33 million.

EME had short-term obligations of $78 million at December 31, 2002, consisting of promissory notes related to Contact Energy. The fair values of these obligations approximated their carrying values at December 31, 2002 and would not have been materially affected by changes in market interest rates. The fair market values of long-term fixed interest rate obligations are subject to interest rate risk. The fair market value of EME's total long-term obligations (including current portion) was $4.9 billion at December 31, 2002, compared to the carrying value of $6.0 billion. A 10% increase in market interest rates at December 31, 2002, would result in a decrease in the fair value of total long-term obligations by approximately $110 million. A 10% decrease in market interest rates at December 31, 2002 would result in an increase in the fair value of total long-term obligations by approximately $127 million.

Foreign Exchange Rate Risk

Fluctuations in foreign currency exchange rates can affect, on a U.S. dollar equivalent basis, the amount of EME's equity contributions to, and distributions from, its international projects. 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 U.S. dollars or other indices reasonably expected to correlate with foreign exchange movements. In addition, EME has used statistical forecasting techniques to help assess foreign exchange risk and the probabilities of various outcomes. EME cannot provide assurances, however, that fluctuations in exchange rates will be fully offset by hedges or that currency movements and the relationship between certain macroeconomic variables will behave in a manner that is consistent with historical or forecasted relationships.

The First Hydro plant in the U.K. and the plants in Australia have been financed in their local currencies, pounds sterling and Australian dollars, respectively, thus hedging the majority of their acquisition costs against foreign exchange fluctuations. Furthermore, EME has evaluated the return on the remaining equity portion of these investments with regard to the likelihood of various foreign exchange scenarios. These analyses use market-derived volatilities, statistical correlations between specified variables, and long-term forecasts to predict ranges of expected returns.

During 2002, foreign currencies in the U.K., Australia and New Zealand increased in value compared to the U.S. dollar by 11%, 10% and 26%, respectively (determined by the change in the exchange rates from December 31, 2001 to December 31, 2002). The increase in value of these currencies was the primary reason for the foreign currency translation gain of $125 million during 2002. A 10% increase or decrease in the exchange rates at December 31, 2002 would result in foreign currency translation gains or losses of $93 million.

Contact Energy enters into foreign currency forward exchange contracts to hedge identifiable foreign currency commitments associated with transactions in the ordinary course of business. The contracts are primarily in Australian and U.S. dollars with varying maturities through August 2003. At December 31, 2002, the outstanding notional amount of the contracts totaled $10 million and the fair value of the contracts totaled $(151,000). Contact Energy recognized a foreign exchange loss of $1 million in 2002, compared to a foreign exchange gain of $1 million in 2001 related to the contracts that matured during the respective periods. A 10% decrease in the exchange rates at December 31, 2002 would result in a $2 million increase in the fair value of the contracts.

In addition, Contact Energy enters into cross currency interest rate swap contracts in the ordinary course of business. These cross currency swap contracts involve swapping fixed and floating-rate U.S. and Australian dollar loans into floating-rate New Zealand dollar loans with varying maturities through April 2018.

EME will continue to monitor its foreign exchange exposure and analyze the effectiveness and efficiency of hedging strategies in the future.

Non-Trading Derivative Financial Instruments

The following table summarizes the fair values for outstanding derivative financial instruments used for purposes other than trading by risk category and instrument type:

In millions December 31,	**2002**	2001
Derivatives:		
Interest rate:		
Interest rate swap/cap agreements	**$ (48)**	$ (36)
Interest rate options	**(2)**	(1)
Commodity price:		
Electricity	**(100)**	(74)
Natural gas	**—**	(8)
Foreign currency forward exchange agreements	**—**	(1)
Cross currency interest rate swaps	**(2)**	28

In assessing the fair value of EME's non-trading derivative financial instruments, EME uses a variety of methods and assumptions based on the market conditions and associated risks existing at each balance sheet date. The fair value of commodity price contracts takes into account quoted market prices, time value of money, volatility of the underlying commodities and other factors. The fair value of outstanding derivative commodity price contracts that would be expected after a ten percent adverse price change at December 31, 2002 is $(53) million. The following table summarizes the maturities, the valuation method and the related fair value of EME's commodity price risk management assets and liabilities (as of December 31, 2002):

In millions	Total Fair Value	Maturity <1 year	Maturity 1 to 3 years	Maturity 4 to 5 years	Maturity >5 years
Prices actively quoted	$ (10)	$ (10)	$ —	$ —	$ —
Prices based on models and other valuation methods	(90)	3	(7)	(13)	(73)
Total	$ (100)	$ (7)	$ (7)	$ (13)	$ (73)

The fair value of the electricity rate swap agreements (included under commodity price-electricity) entered into by the Loy Yang B plant and the First Hydro plant has been estimated by discounting the future net cash flows resulting from the difference between the average aggregate contract price per MW and a forecasted market price per MW multiplied by the number of MW remaining to be sold under the contract.

Energy Trading Derivative Financial Instruments

On September 1, 2000, EME acquired the trading operations of Citizens Power LLC and, subsequently, combined them with EME's risk management and trading operations, now conducted by its subsidiary, Edison Mission Marketing & Trading. As a result of a number of industry and credit related factors, Edison Mission Marketing & Trading has minimized its price risk management activities and its trading activities with third parties not related to EME's power plants or investments in energy projects. See "Current Developments—EME Current Developments." To the extent Edison Mission Marketing & Trading engages in trading activities, Edison Mission Marketing & Trading seeks to manage price risk and to create stability of future income by selling electricity in the forward markets and, to a lesser degree, to generate profit from price volatility of electricity and fuels by buying and selling these commodities in wholesale markets. EME generally balances forward sales and purchase contracts and manages its exposure through a value at risk analysis as described under "—Commodity Price Risk."

The fair value of the commodity financial instruments related to energy trading activities, are set forth below:

	December 31, 2002		December 31, 2001	
In millions	**Assets**	**Liabilities**	Assets	Liabilities
Electricity	**$ 109**	**$ 15**	$ 7	$ 5
Other	**—**	**2**	2	2
Total	**$ 109**	**$ 17**	$ 9	$ 7

The fair value of trading contracts that would be expected after a ten percent adverse price change at December 31, 2002, are shown in the table below:

In millions	Fair Value	Fair Value After 10% Adverse Price Change
Electricity	$ 94	$ 93
Other	(2)	(2)
Total	$ 92	$ 91

The change in the fair value of trading contracts was as follows:

In millions	Amount
Fair value of trading contracts at January 1, 2002	$ 2
Purchase of power sales agreement	80
Net gains from energy trading activities	42
Amount realized from energy trading activities	(32)
Fair value of trading contracts at December 31, 2002	$ 92

Quoted market prices are used to determine the fair value of the financial instruments related to energy trading activities, except for the power sales agreement with an unaffiliated electric utility that EME's subsidiary purchased and restructured and a long-term power supply agreement with another unaffiliated party. EME's subsidiary recorded these agreements at fair value based upon a discounting of future electricity prices derived from a proprietary model using a discount rate equal to the cost of borrowing the non-recourse debt incurred to finance the purchase of the power supply agreement.

The following table summarizes the maturities, the valuation method and the related fair value of energy trading assets and liabilities (as of December 31, 2002):

In millions	Total Fair Value	Maturity <1 year	Maturity 1 to 3 years	Maturity 4 to 5 years	Maturity >5 years
Assets:					
Prices actively quoted	$ (1)	$ (1)	$ —	$ —	$ —
Prices based on models and other valuation methods	93	(3)	4	7	85
Total	$ 92	$ (4)	$ 4	$ 7	$ 85

EME's net gains (losses) arising from energy trading activities recognized on a fair value basis are as follows:

In millions Years ended December 31,	**2002**	2001	2000
Unrealized gains (losses), net	**$ 10**	$ (12)	$ 12
Realized gains, net	**32**	22	50
Total	**$ 42**	$ 10	$ 62

Edison Capital's Market Risks

Edison Capital is exposed to interest rate risk, foreign currency exchange rate risk and credit and performance risk that could adversely affect its results of operations or financial position.

Interest Rate Risk

Changes in interest rates and fluctuations in foreign currency exchange rates can have an 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. The nature and amount of Edison Capital's long- and short-term debt can be expected to vary as a result of future business requirements and other factors.

At December 31, 2002, 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, 2002, a 10% increase in market interest rates would have resulted in an $8 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 $9 million increase in the fair market value of Edison Capital's long-term debt.

Foreign Currency Exchange Risk

At December 31, 2002, Edison Capital's outstanding debt included £75 million (approximately $121 million) that is subject to foreign currency exchange fluctuations.

Credit and Performance Risk

Edison Capital's investments may be affected by the financial condition of other parties, the performance of the asset, economic conditions and other business and legal factors. Edison Capital generally does not control operations or management of the projects and must rely on the skill, experience and performance of third party project operators or managers. These third parties may experience financial difficulties or otherwise become unable or unwilling to perform their obligations. This concern has increased with respect to energy companies and airlines.

Edison Capital's investments generally depend upon the operating results of a project with a single asset. These results may be affected by general market conditions, equipment or process failures, disruptions in important fuel supplies or prices, or another party's failure to perform material contract obligations. Edison Capital has taken steps to mitigate these risks in the structure of each project through contract requirements, warranties, insurance, collateral rights and default remedies, but such measures may not be adequate to assure full performance. In the event of default, lenders with a security interest in the asset may exercise remedies that could lend to a loss of some or all of Edison Capital's investment in the project.

Edison Capital has leased three aircraft to American Airlines. American Airlines reports significant operating losses, and there is increasing concern that American Airlines may file bankruptcy. If American files bankruptcy, or otherwise defaults in making its lease payments, the lenders with a security interest in the aircraft may exercise remedies that could lead to a loss of some or all of Edison Capital's investment in the aircraft plus any accrued interest. The total maximum loss exposure to Edison Capital in 2003 is $48 million. A voluntary restructure of the lease could also result in a loss of some or all of the investment. At December 31, 2002, American Airlines was current in its lease payments and was publicly expressing a desire to avoid bankruptcy.

SCE'S REGULATORY MATTERS

In the mid-1990s, state lawmakers and the CPUC initiated the electric industry restructuring process. Under state law, beginning in January 1, 1998, a multi-year freeze on the rates SCE could charge its customers was implemented. In addition, a transition cost recovery mechanism was adopted to allow SCE to recover its stranded costs associated with generation-related assets. These frozen rates (except for the surcharge effective in 2001) 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. As a result of CPUC orders, SCE divested its gas-fired generation plants, representing approximately 9,500 MW of capacity. Between May 2000 and June 2001, prices charged by sellers of power escalated far beyond what SCE was allowed by the CPUC to charge its customers. As a result, SCE incurred $2.7 billion (after tax), or $4.7 billion (pre-tax), in write-offs through August 31, 2001. In January 2001, the State of California began purchasing power on behalf of SCE's customers because SCE's financial condition prevented it from purchasing power supplies for its customers. In a lawsuit filed against the CPUC in November 2000, SCE asserted claims under the federal "filed rate doctrine," for recovery of its electricity procurement related costs. See "—CPUC Litigation Settlement Agreement" for further discussion of the lawsuit.

SCE has restored substantially all of its write-offs as a result of the implementation of a settlement with the CPUC of the filed rate doctrine lawsuit in fourth quarter 2001 and the CPUC's URG decision in second quarter 2002 to return SCE's retained generation assets to cost-based ratemaking. In addition, on January 1, 2003, SCE resumed procurement of its residual net short position.

This section of the MD&A presents SCE's regulatory matters using three main subsections: generation and power procurement, transmission and distribution, and other regulatory matters.

Generation and Power Procurement

This subsection of "SCE's Regulatory Matters" discusses: the settlement agreement with the CPUC to allow recovery of undercollected power procurement costs arising from the California energy crisis in 2000 and 2001 and an intervenor's lawsuit seeking to overturn this agreement; the PROACT regulatory asset allowed in the settlement agreement; separate proceedings related to direct access, surcharge decisions, hedging cost recovery, the return of utility-retained generation assets to cost-based ratemaking, power procurement, the allocation of the CDWR contracts; and the ultimate disposition of Mohave.

CPUC Litigation Settlement Agreement

In November 2000, SCE filed a lawsuit against the CPUC in federal district court seeking a ruling that SCE is entitled to full recovery of its electricity procurement costs incurred during the energy crisis in accordance with the tariffs filed with the FERC. In October 2001, the federal district court entered a stipulated judgment approving an agreement between the CPUC and SCE to settle the pending lawsuit.

On January 23, 2002, the CPUC adopted a resolution implementing the settlement agreement. See discussion below in "—PROACT Regulatory Asset."

Key elements of the settlement agreement include the following items:

- Establishment of the PROACT, as of September 1, 2001, with an opening balance equal to the amount of SCE's procurement-related liabilities as of August 31, 2001, less SCE's cash and cash equivalents as of that date, and less $300 million.

- Beginning on September 1, 2001, SCE will apply to the PROACT, on a monthly basis, the difference between SCE's revenue from retail electric rates (including surcharges) and the costs that SCE is authorized by the CPUC to recover in retail electric rates. Unrecovered obligations in the PROACT will accrue interest from September 1, 2001.

- Maintain current rates (including surcharges) in effect until December 31, 2003, subject to certain adjustments, or, if earlier, until the date that SCE recovers the entire PROACT balance. If SCE has not recovered the entire balance by December 31, 2003, the unrecovered balance will be amortized in rates for up to an additional two years.

- During the period that SCE is recovering its previously incurred procurement-related obligations, no penalty will be imposed by the CPUC on SCE for any noncompliance with CPUC-mandated capital structure requirements.

- SCE can incur up to $250 million of costs to acquire financial instruments and engage in other transactions intended to hedge fuel cost risks associated with SCE's retained generation assets and power purchase contracts with QFs and other utilities. See discussion in "Market Risk Exposures—SCE's Market Risks" and "—Hedging Cost Recovery Decision."

- SCE will not declare or pay dividends or other distributions on its common stock (all of which is held by its parent) prior to the earlier of the date SCE has recovered all of its procurement-related obligations in the PROACT or January 1, 2005. However, if SCE has not recovered all of its procurement-related obligations by December 31, 2003, SCE may apply to the CPUC for consent to resume common stock dividends, and the CPUC will not unreasonably withhold its consent.

- Subject to certain qualifications, SCE will cooperate with the CPUC and the California Attorney General to pursue and resolve SCE's claims and rights against sellers of energy and related services, SCE's defenses to claims arising from any failure to make payments to the PX or ISO, and similar claims by the State of California or its agencies against the same adverse parties. During the recovery period discussed above, refunds obtained by SCE related to its procurement-related liabilities will be applied to the balance in the PROACT. See "—Wholesale Electricity Markets."

The settlement agreement states that one of its purposes is to restore the investment grade creditworthiness of SCE as rapidly as reasonably practicable so that it will be able to provide reliable electrical service as a state-regulated entity as it has in the past. SCE cannot provide assurance that it will regain investment grade credit ratings by any particular date.

TURN and other parties appealed to the federal court of appeals seeking to overturn the stipulated judgment of the district court that approved the settlement agreement. On March 4, 2002, the United States Court of Appeals for the Ninth Circuit heard argument on the appeal, and on September 23, 2002 the court issued its opinion. In the opinion, the court affirmed the district court on all claims, with the exception of the challenges founded upon California state law, which the appeals court referred to the California Supreme Court. Specifically, the appeals court affirmed the district court in the following respects: (1) the district court did not err in denying the motions to intervene brought by entities other than TURN; (2) the district court did not err in denying standing for the entities other than TURN to appeal the stipulated judgment; (3) the district court was not deprived of original jurisdiction over the lawsuit; (4) the district court did not err in declining to abstain from the case; (5) the district court did not exceed its authority by approving the stipulated judgment without TURN's consent; (6) the district court's approval of the settlement agreement did not deny TURN due process; and (7) the district court did not violate the Tenth Amendment of the United States Constitution in approving the stipulated judgment. In sum, the appeals court concluded that none of the substantive arguments based on federal statutory or constitutional law compelled reversal of the district court's approval of the stipulated judgment.

However, the appeals court stated in its opinion that there is a serious question whether the settlement agreement violated state law, both in substance and in the procedure by which the CPUC agreed to it. The appeals court added that if the settlement agreement violated state law, the CPUC lacked capacity to consent to the stipulated judgment, and the stipulated judgment would need to be vacated. The appeals court indicated that, on a substantive level, the stipulated judgment appears to violate California's electric industry restructuring statute providing for a rate freeze. The appeals court also indicated that, on a procedural level, the stipulated judgment appears to violate California laws requiring open meetings and public hearings. Because federal courts are bound by the pronouncements of the state's highest court on applicable state law, and because the federal appeals court found no controlling precedents from California courts on the issues of state law in this case, the appeals court issued a separate order certifying those issues in question form to the California Supreme Court and requested that the California Supreme Court accept certification.

The appeals court stayed further proceedings in the case pending a response from the California Supreme Court on the request for certification. The appeals court did not stay the continued operation of the settlement agreement, thus collection of past procurement costs under PROACT is continuing. On October 29, 2002, SCE filed briefs requesting that the California Supreme Court answer the appeals' court certification and requesting that the hearing of the matter be placed on the California Supreme Court's March 2003 calendar, or heard at the court's earliest convenience and requesting that the California Supreme Court reformulate one of the certified questions. On November 20, 2002, the California Supreme Court issued an order indicating that it would hear the case, and would reformulate the certified question as requested by SCE. The court ordered that all briefing be submitted by March 2003 and further stated that the case would be scheduled for expedited oral argument after briefing has been completed. SCE and the CPUC filed their respective opening briefs on the merits of the certified questions. TURN filed its answering brief, and SCE and the CPUC filed reply briefs. Various third parties, including the Governor, submitted friend-of-the-court briefs concerning the certified questions. In addition, the California Supreme Court requested that the parties provide supplemental briefing with respect to an issue related to California's open meeting laws. The parties have complied with such request. SCE continues to operate under the settlement agreement. SCE continues to believe it is probable that SCE ultimately will recover its past procurement costs through regulatory mechanisms, including the PROACT. However, SCE cannot predict with certainty the outcome of the pending legal proceedings.

PROACT Regulatory Asset

In accordance with the settlement agreement and an implementing resolution adopted by the CPUC, in the fourth quarter of 2001, SCE established the PROACT regulatory balancing account, with an initial balance of $3.6 billion reflecting the net amount of past procurement-related liabilities to be recovered by SCE. Each month, SCE applies to the PROACT the positive or negative difference between SCE's revenue from retail electric rates (including surcharges) and the costs that SCE is authorized by the CPUC to recover in retail electric rates. The balance in the PROACT was $2.6 billion at December 31, 2001, $574 million on December 31, 2002 and $594 million on February 28, 2003. SCE previously projected that it would recover the remaining balance of the procurement-related obligations in the PROACT by the end of 2003. Based on decisions made by the CPUC at the end of 2002, SCE now believes it will recover the PROACT balance by mid-2003. There still exist potential factors that could change SCE's estimate of the timing of PROACT recovery. These factors include:

- the level of output of SCE's generating plants and contract power deliveries (for example, lower than forecasted output could slow PROACT recovery);
- authorized revenue changes for distribution, transmission, and SCE retained-generation costs (see discussion in "—2003 General Rate Case Proceeding", "—PBR Decision" and "—URG Decision");

- outcome of issues currently being addressed in the CPUC's power procurement proceedings, including further adjustments to the CPUC-authorized allocation among the California utilities of power contracted by the CDWR for 2003 and the related CDWR revenue requirement impacts;

- SCE's share of the CDWR revenue requirement (see discussion in "—CDWR Power Purchases and Revenue Requirement Proceedings");

- level of retail sales (for example, higher than forecasted sales would accelerate PROACT recovery);

- level of direct access (see "—Direct Access Proceedings" discussions below);

- direct access customers' contribution to recovery of SCE's PROACT-related costs and to the CDWR's costs (see "—Direct Access Proceedings" discussions regarding the historical procurement charge and exit fees below);

- a decision by the CPUC, which could be made under the settlement agreement, directing $150 million of surplus revenue to be used for any utility purpose (which would delay PROACT recovery); and

- potential energy supplier refunds (see discussion in "—Wholesale Electricity Markets").

The following is an update on various regulatory proceedings impacting the timing of PROACT recovery:

Direct Access Proceedings

Direct Access – Historical Procurement Charge

From 1998 through mid-September 2001, SCE's customers were able to choose to purchase power directly from an energy service provider other than SCE (thus becoming direct access customers) or continue to purchase power from SCE. (Customers who continue to purchase power from SCE are referred to as bundled service customers). On March 21, 2002, the CPUC issued a final decision affirming that new direct access arrangements entered into by SCE's customers after September 20, 2001 are invalid. This decision did not affect direct access arrangements in place before that date. Direct access customers receive a credit for the generation costs SCE saves by not serving them. Electric utility revenue is reported net of this credit. Because of this credit, direct access power purchases resulted in additional undercollected power procurement costs to SCE during 2000 and 2001. On July 17, 2002, the CPUC issued an interim decision to establish a nonbypassable historical procurement charge requiring direct access customers to pay $391 million of SCE's past power procurement costs and directed SCE to reduce the PROACT balance by $391 million and create a new regulatory asset for the same amount. The historical procurement charge is to be collected from direct access customers by reducing their existing generation credit by 2.7¢ per kWh (effective July 27, 2002) until the CPUC issues and implements an order to determine a surcharge for direct access customers' share of the CDWR's costs, as discussed in the paragraph below. Once that surcharge was implemented on January 1, 2003, the contribution by direct access customers to the historical procurement charge was reduced from 2.7¢ per kWh to 1¢ per kWh until the $391 million is collected, with the remainder of the 2.7¢ per kWh utilized for CDWR's costs associated with direct access customers. On October 16, 2002, SCE filed a petition with the CPUC to modify the historical procurement charge interim decision to provide that direct access customers be responsible for $497 million of SCE's past procurement costs. In subsequent testimony, SCE reduced its request to $493 million. Once the interim decision becomes permanent, SCE will evaluate whether a new regulatory asset could be created. If such a regulatory asset was created, the net effect of this action would be to accelerate PROACT recovery. Evidentiary hearings on SCE's petition to modify were held on March 4, 2003, and a decision is expected in May or June 2003.

Direct Access – Exit Fees

In addition to the historical procurement charge, the CPUC, in a November 7, 2002 decision, assigned responsibility for a portion of four other cost categories to the direct access customers. The first category consists of the CDWR's power procurement costs incurred between January 17, 2001 and September 30, 2001. The CDWR sold approximately $11 billion in bonds in fourth quarter 2002 to repay the amounts it borrowed to pay these costs. The CPUC decision stated that the direct access customers are responsible for paying a portion of the bond charge to recover the principal and financing costs associated with these bonds. The second category relates to the CDWR's power procurement costs for the last quarter of 2001 and the year 2002. The CPUC stated that direct access customers must pay a share of these costs to make bundled service customers indifferent to suspension by the CPUC of the direct access program on September 20, 2001. The third category includes the CDWR long-term contract costs for 2003 and beyond. The CPUC decision stated that a portion of these costs should be paid by direct access customers to keep bundled service customers indifferent to the later suspension of direct access on the premise that the CDWR signed some of its long-term contracts with the expectation of serving the load that switched to direct access after July 1, 2001. Finally, the last category relates to the above-market costs of SCE's URG (e.g., qualifying facilities contract costs) that pursuant to AB 1890 are to be recovered from all customers on an ongoing basis. The CPUC decision states that: (1) the bond charge is applicable to all direct access customers except those who were continuously on direct access and never used any CDWR power (less than 1% of SCE's load); (2) the next two categories of costs are applicable to direct access customers who took bundled service at any time after February 1, 2001; and (3) the last category is applicable to all direct access customers, including continuous direct access customers. The cap on the amount of exit fees to be paid by direct access customers will be addressed in hearings scheduled to begin in early April 2003. The exact amount of exit fees to be paid by direct access customers will be determined on an annual basis after the CDWR's submission of its requested revenue requirement to the CPUC.

The impact of the November 7, 2002 decision is incorporated into SCE's current projection of the timing of PROACT recovery.

Surcharge Decisions

A March 2001 CPUC decision authorized a 3¢-per-kWh revenue surcharge and made permanent a 1¢-per-kWh temporary surcharge authorized in January 2001, with the restriction that the revenue arising from both surcharges apply only to ongoing procurement charges and future power purchases. On November 7, 2002, the CPUC issued a decision modifying the March 2001 decision to allow the surcharge revenue to be used not only for power costs but also for returning SCE to reasonable financial health. The decision stated that the extent to which the surcharge revenue could be used for future power costs or obtaining reasonable financial health would be the subject of future proceedings. The decision ordered SCE to continue tracking the surcharge revenue in balancing accounts, subject to later adjustment and possible refund. See "—Customer Rate-Reduction Plan." This decision is incorporated into SCE's current projection of the timing of PROACT recovery.

The CPUC allowed the continuation of the 0.6¢-per-kWh temporary surcharge that was scheduled to terminate in June 2002 and required SCE to track the associated revenue in a balancing account for rate-making purposes, until the CPUC determines the use of the surcharge. The continuation of the surcharge resulted in a $187 million cash increase in 2002 and is expected to result in an increase of $352 million in 2003, but has no impact on earnings. A December 17, 2002, CPUC decision authorized SCE to use the revenue associated with this surcharge to partially offset its and the CDWR's higher 2003 revenue requirement, and SCE has incorporated that assumption into its current projection of the timing of PROACT recovery. For financial reporting purposes, amounts billed in 2002 as a result of this surcharge are credited to a regulatory liability account, because the surcharge is to be used to recover costs to be incurred in the future. This account will be amortized into revenue in 2003.

Hedging Cost Recovery Decision

Pursuant to its authority mentioned in "—CPUC Litigation Settlement Agreement," SCE purchased $209 million in hedging instruments (gas call options) in late 2001 to hedge a majority of its natural gas price exposure associated with QF contracts for 2002 and 2003. A February 13, 2003 CPUC decision allows

SCE to transfer the entire $209 million into the PROACT regulatory asset during first quarter 2003. SCE has incorporated this decision into its current projection of the timing of PROACT recovery.

URG Decision

On April 4, 2002, the CPUC issued a decision to return generation assets retained by SCE (utility-retained generation) to cost-of-service ratemaking until the implementation of the 2003 general rate case (GRC) proceeding described below. The URG decision:

- Allows recovery of incurred costs for all URG components other than San Onofre Units 2 and 3, subject to reasonableness review by the CPUC;

- Retains the incremental cost incentive pricing mechanism (ICIP) for San Onofre Units 2 and 3 through 2003;

- Establishes an amortization schedule for SCE's nuclear facilities that reflects their current remaining Nuclear Regulatory Commission license durations, using unamortized balances as of January 1, 2001 as a starting point;

- Establishes balancing accounts for the costs of utility generation, purchased power, and ancillary services from the ISO; and

- Continues the use of SCE's last CPUC-authorized return on common equity of 11.6% for SCE's URG rate base other than San Onofre Units 2 and 3, and keeps in place the 7.35% return on rate base for San Onofre Units 2 and 3 under the ICIP.

Based on this decision, during the second quarter of 2002, SCE reestablished for financial reporting purposes regulatory assets related to its unamortized nuclear facilities, purchased-power settlements and flow-through taxes, reduced the PROACT regulatory asset balance (by $256 million), and recorded a corresponding credit to earnings of $480 million after tax. The reduction in the PROACT balance reflects a change in SCE's unamortized nuclear facilities amortization schedule to reflect a ten-year amortization period rather than a four-year amortization period, which was used to calculate the surplus revenue contributed to the PROACT, for rate-making purposes, during the last four months of 2001.

CDWR Power Purchases and Revenue Requirement Proceedings

In accordance with an emergency order signed by the governor, the CDWR began making emergency power purchases for SCE's customers on January 17, 2001. Amounts SCE bills to and collects from its customers for electric power purchased and sold by the CDWR are remitted directly to the CDWR and are not recognized as revenue by SCE. In February 2001, AB 1 (First Extraordinary Session, AB 1X) was enacted into law. AB 1X authorized the CDWR to enter into contracts to purchase electric power and sell power at cost directly to SCE's retail customers, and authorized the CDWR to issue bonds to finance electricity purchases. In addition, the CPUC has the responsibility to allocate the CDWR's revenue requirement among the customers of SCE, Pacific Gas and Electric (PG&E), and San Diego Gas & Electric (SDG&E).

On February 21, 2002, the CPUC allocated to SCE's customers $3.5 billion (38.2%) of the CDWR's total power procurement revenue requirement of $9 billion for the period 2001 and 2002. This resulted in an average annual CDWR revenue requirement of $1.7 billion being allocated to SCE. In its February 21, 2002 decision, the CPUC ordered that allocation of that revenue requirement to each utility be trued-up based on the CDWR's actual recorded costs for the 2001–2002 period and a specific methodology set forth in that decision.

On October 24, 2002, the CPUC issued a decision that adopts a methodology for establishing a charge to repay the CDWR's $11 billion bond issue. The bond charge is to be set by dividing the annual revenue requirement for bond-related costs by an estimate of the annual electricity consumption of bundled service customers subject to the charge. The charge will apply to electricity consumed on and after November 15, 2002, and will be set annually based on annual expected debt-related costs and projected electricity consumption. For 2003, the CPUC allocated to SCE's customers $331 million (about 44%) of the CDWR's bond charge revenue requirement of $745 million. The bond charge is set at a rate of 0.513¢ per kWh for SCE's customers. In a November 7, 2002 decision, the CPUC assigned responsibility for a portion of the bond charge to direct access customers (see "—Direct Access—Exit Fees"). This decision is incorporated into SCE's current projection of the timing of PROACT recovery.

On December 17, 2002, the CPUC adopted an allocation of the CDWR's forecast power procurement revenue requirement for 2003, based on the quantity of electricity expected to be supplied under the CDWR contracts to customers of each of the three utility companies by the CDWR. SCE's allocated share is $1.9 billion of the CDWR's total 2003 power procurement revenue requirement of $4.5 billion. In a February 13, 2003 decision on rehearing of the December 17, 2002 decision, the CPUC increased the CDWR's total revenue requirement by $29 million, restoring it to the level originally requested by the CDWR. This is an interim allocation and will be superseded by a later allocation after the CDWR submits a supplemental determination of its 2003 revenue requirement. The CPUC stated that the later allocation could result in a reduction in the CDWR's revenue requirement, with a corresponding decrease in the CDWR's rate charged to bundled service customers. The CPUC's December 17, 2002 decision did not address issues relating to the true-up of the CDWR's 2001-2002 revenue requirement, stating that those issues will be addressed after actual data for 2002 becomes available, expected in April 2003. A true-up of the CDWR's revenue requirement, as well as the additional allocation of contracts, have not been incorporated into SCE's current projection of the timing of PROACT recovery.

Generation Procurement Proceedings

In October 2001, the CPUC issued an Order Instituting Rulemaking directing SCE and the other major California electric utilities to provide recommendations for establishing policies and mechanisms to enable the utilities to resume power procurement by January 1, 2003. Although the proceeding began before the enactment of AB 57, that statute (in its draft form, and, after enactment, in its final form) has guided the proceeding. Senate Bill (SB) 1078 has also had an impact on this proceeding, as described below.

AB 57, which provides for SCE and the other California utilities to resume procuring power for their customers, was signed into law by the Governor of California in September 2002. A second senate bill was enacted not long after AB 57 to shorten the period between the adoption of a utility's initial procurement plan and the resumption of procurement from 90 days to 60 days. Under these statutes, SCE is effectively allowed to recover procurement costs incurred in compliance with an approved procurement plan. Only limited categories of costs, including contract administration and least-cost dispatch, are subject to reasonableness reviews.

In addition, SB 1078, which was signed into law by the Governor in September 2002 and is effective January 1, 2003, provides that, commencing January 1, 2003, SCE and other California utilities shall increase their procurement of renewable resources by at least an additional 1% of their annual electricity sales per year so that 20% of the utility's annual electricity sales are procured from renewable resources by no later than December 31, 2017. Utilities are not required to enter into long-term contracts for renewable resources in excess of a market-price benchmark to be established by the CPUC pursuant to criteria set forth in the statute. Similar provisions are also found in AB 57.

The CPUC issued four major decisions in this proceeding in 2002 addressing: (1) transitional procurement contracts; (2) the allocation of contracts previously entered into by the CDWR among the three major California utilities; (3) the resumption of power procurement activities by these utilities on January 1, 2003 and adoption of a regulatory framework for such activities; and (4) SCE's short-term procurement plan for 2003.

The first decision, relating to transitional procurement contracts, was issued on August 22, 2002. It authorized the utilities to enter into capacity contracts between the effective date of the decision and January 1, 2003, referred to as the transitional procurement period. Under this decision, the CPUC would approve or disapprove the transitional contracts proposed by a utility by means of an expedited advice letter process. As a result of this process, SCE entered into six transitional capacity contracts with terms up to five years. These contracts were approved by the CPUC.

This decision also required the utilities to procure, during the transitional procurement period, at least 1% of their annual electricity sales through a competitive procurement process set aside for renewable resources. The utilities were required to solicit bids for renewable contracts with terms of five, ten and fifteen years and to enter into contracts providing for the commencement of deliveries by the end of 2003. In accordance with this CPUC directive, SCE conducted a solicitation of offers from owners of renewable resources and, based upon the results of the solicitation, provisionally entered into six contracts, subject to subsequent CPUC approval.

On December 24, 2002 and January 14, 2003, SCE filed advice letters seeking CPUC approval of these six renewable contracts. On January 30, 2003, the CPUC issued a resolution approving four of the six renewable contracts. In addition, draft resolutions have been issued disapproving the two remaining renewable contracts, with an alternative draft resolution approving one of the two remaining contracts. The CPUC is expected to rule on the remaining contracts in the second quarter of 2003.

The second decision addressed the issue of allocating among the three major California utilities the contracts previously entered into by the CDWR. In this decision, issued on September 19, 2002, the CPUC allocated the CDWR contracts on a contract-by-contract basis. Under the decision, utility responsibility for the contracts is limited to that of scheduling and dispatch. The decision significantly reduces SCE's net short and also increases the likelihood that SCE will have excess power during certain periods. Wholesale revenue from the sale of such surplus energy is to be prorated between the CDWR and SCE, pursuant to several CPUC orders. Under the decision, SCE acts as limited agent for the CDWR for contract implementation, but legal title, financial reporting and responsibility for the payment of contract-related bills remain with the CDWR. On January 17, 2003, the CDWR filed a petition to modify the September 19, 2002 decision requesting the allocation of four additional contracts that are not currently part of the CDWR's 2003 revenue requirement. The CPUC allocated one of the four contracts to SCE in a February 27, 2003 decision.

The third decision was issued on October 24, 2002. It ordered the utilities to resume procurement and adopting the regulatory framework for the utilities resuming full procurement responsibilities on January 1, 2003. The decision distinguished the utilities' responsibilities on the basis of short-term (2003) versus long-term (2004–2024) procurement. It adopted the utilities' procurement plans filed on May 1, 2002 and directed that they be modified prior to January 1, 2003 to reflect the decision, the allocation of existing CDWR contracts, and any transitional procurement done under the August 22, 2002 decision. The October 24, 2002 decision also set forth a detailed process and procedural schedule to develop long-term procurement planning that includes the filing by each utility of a long-term plan by April 1, 2003 and an evidentiary hearing in early July 2003. In addition, the decision called for each of the utilities to establish a balancing account, to be known as the energy resource recovery account, to track energy costs. These balancing accounts will be used for examining procurement rate adjustments on a semi-annual basis, as well as on a more expedited basis in the event fuel and purchased-power costs exceed a prescribed threshold. The decision also provided clarification as to certain elements of the CPUC's August 22, 2002 order regarding interim procurement of additional renewable resources and established a schedule for parties to provide comments in January 2003 on various aspects of SB 1078 implementation in anticipation of an implementation report to be submitted by the CPUC to the legislature by June 30, 2003. On November 25, 2002, SCE filed an application with the CPUC for rehearing of the October 24 decision seeking the correction of legal errors in the decision. The CPUC has not yet ruled on SCE's application for rehearing, but has indicated that it will address SCE's application and others in future decisions.

The fourth decision, issued on December 19, 2002, approved modified short-term procurement plans filed in November 2002 by SCE, PG&E, and SDG&E. It modified and clarified the cost-recovery mechanisms and standards of behavior adopted in the October 24 decision, and provided further guidance on the long-term planning process to be undertaken in the next phase of the power procurement proceeding. The CPUC found that the utilities were capable of resuming full procurement on January 1, 2003 and ordered that they take all necessary steps to do so.

Among other things, the December 19, 2002 decision determined that SCE's maximum disallowance risk exposure for procurement activities, contract administration and least-cost dispatch would be capped at twice SCE's "annual procurement administrative expenses."

On January 21, 2003, SCE filed an application for rehearing of the December 19, 2002 procurement plan decision. Issues addressed included certain standard of conduct provisions, bilateral contracting, level of customer risk tolerance, lack of an appropriate tracking mechanism for certain costs, lack of definition for least cost dispatch, and the finding that SCE was non-compliant with the August 22, 2002 decision. SCE has filed a petition for modification which addressed, among other things, the need for the cap on SCE's maximum disallowance risk exposure to be extended to cover all procurement activities.

On March 4, 2003, SCE also filed a motion for consolidated consideration of the numerous applications for rehearing and petitions for modification that have been filed, and will be filed, on the various CPUC decisions addressing the investor owned utilities management of their power supply portfolios. In the motion, SCE urged the CPUC to conduct a comprehensive review of its procurement decisions and act on the various applications for rehearing and petitions for modification in an integrated manner, avoiding the piecemeal action that failed to fully resolve the outstanding issues.

In accordance with the CPUC's October 24, 2002 decision, on February 3, 2003, SCE and the other utilities filed outlines of their long-term procurement plans. SCE proposed in its outline that the CPUC separate the proceeding so that SCE would file a separate 2004 short-term procurement plan as well as its long-term plan. The assigned administrative law judge agreed with this proposal. SCE plans to file the long-term resource plan and the 2004 short-term procurement plan on April 1, 2003 and May 1, 2003, respectively. Hearings on the short-term plan and certain key issues in the long-term plan are expected to take place in June and July 2003. The issues that will be incorporated into the long-term plan were addressed during the prehearing conference on March 7, 2003. Pursuant to a ruling of the assigned administration law judge, issues related to implementation of SB 1078 will be determined on a separate, expedited schedule. Testimony on the implementation of SB 1078 will be filed on March 27, 2003 and hearings will be held in April 2003. A preliminary decision is expected in June 2003, followed by a report by the CPUC to the Legislature on June 30, 2003.

CDWR Contracts

On December 19, 2002, the CPUC adopted an operating order under which SCE, PG&E, and SDG&E perform the operational, dispatch, and administrative functions for the CDWR's long-term power purchase contracts, beginning January 1, 2003. The operating order sets forth the terms and conditions under which the three utility companies administer the CDWR contracts and requires the utility companies to dispatch all the generating assets within their portfolios on a least-cost basis for the benefit of their ratepayers. PG&E and SDG&E filed an emergency motion in which they sought to substitute their negotiated operating agreements with the CDWR for the CPUC's operating order. The CPUC has not yet ruled on their motion and it is not clear what impact, if any, a CPUC ruling on their motion will have on SCE. On February 24, 2003, the assigned administrative law judge issued a draft decision approving the two negotiated operating agreements subject to certain additions and deletions to the terms agreed to by the parties. This draft decision is subject to comments and must be approved by the CPUC before it is final.

The CPUC also approved amendments to the servicing agreements between the utilities and the CDWR relating to transmission, distribution, billing, and collection services for the CDWR's purchased power. The servicing order issued by the CPUC identifies the formulas and mechanisms to be used by SCE to remit to the CDWR the revenue collected from SCE's customers for their use of energy from the CDWR contracts that have been allocated to SCE.

Mohave Generating Station Proceeding

On May 17, 2002, SCE filed with the CPUC an application to address certain issues facing the future extended operation of Mohave, which is partly owned by SCE. Mohave obtains all of its coal supply from the Black Mesa Mine in northeast Arizona, located on lands of the Navajo Nation and Hopi Tribe (the Tribes). This coal is delivered from the mine to Mohave by means of a coal slurry pipeline, which requires water that is obtained from groundwater wells located on lands of the Tribes in the mine vicinity.

Due to the lack of progress in negotiations with the Tribes and other parties to resolve several coal and water supply issues, SCE's application stated that it probably would not be possible for SCE to extend

Mohave's operation beyond 2005. Uncertainty over a post-2005 coal and water supply has prevented SCE and the other Mohave co-owners from starting to make approximately $1.1 billion (SCE's share is $605 million) of Mohave-related investments that will be necessary if Mohave operations are to extend past 2005, including the installation of pollution control equipment that must be put in place pursuant to a 1999 Consent Decree related to air quality, if Mohave's operations are extended past 2005.

SCE's May 17, 2002 application requested either: a) pre-approval for SCE to immediately begin spending up to $58 million on Mohave pollution controls in 2003, if by year-end 2002 SCE had obtained adequate assurance that the outstanding coal and slurry-water issues would be satisfactorily resolved; or b) authority for SCE to establish certain balancing accounts and otherwise begin preparing to terminate Mohave's coal-fired operations at the end of 2005.

The CPUC issued a ruling on January 7, 2003, requesting further written testimony from SCE and initial written testimony from other parties on specified issues relating to Mohave and its coal and slurry-water supply. The ruling states that the purpose of the CPUC proceeding is to determine whether it is in the public interest to extend Mohave operations post 2005. In its supplemental testimony submitted on January 30, 2003, SCE stated, among other things, that the currently available information is not sufficient for the CPUC to make this determination at this time. The testimony states that neither SCE nor any other party has sufficient assurance of whether and how the currently unresolved coal and water supply issues will be resolved. Unless all key issues are resolved in a timely way, Mohave will cease operation as a coal-fired plant at the end of 2005 under the terms of the consent decree and the existing coal supply agreements. In that event, there would be no need for the CPUC to make the determination it has described, since extension of the present operating period would not be an option. SCE's supplemental testimony accordingly requests that the CPUC authorize the establishment of the balancing accounts that SCE first requested in its May 17, 2002 application, in order to prepare for an orderly shutdown of Mohave by the end of 2005, but the testimony also states that even with such authorization, SCE will continue to work with the relevant stakeholders to attempt to resolve the issues surrounding Mohave's coal and slurry-water supply.

On January 14, 2003, the Natural Resources Defense Council, Black Mesa Trust and others served a notice of intent to sue the U.S. Department of the Interior and other federal government agencies and individuals, challenging the failure of the government to issue a final permit to Peabody Western Coal Company for the operation of the Black Mesa Mine. The prospective plaintiffs claim that the federal government must begin a proceeding for issuance of a final permit to Peabody rather than allow Peabody to continue long-term operation of the Black Mesa Mine on an interim basis including groundwater extraction for use in the coal slurry pipeline. The notice indicates that the prospective plaintiffs would then challenge any issuance of a permanent mining permit for the Black Mesa Mine unless, at a minimum, an alternate source of slurry water is obtained. If the prospective plaintiffs prevail in any future lawsuit, the coal supply to Mohave could be interrupted.

For additional matters related to Mohave see the "Other Developments—Navajo Nation Litigation" section.

In light of all of the issues discussed above, SCE concluded that it is probable Mohave will be shut down at the end of 2005. Because the expected undiscounted cash flows from the plant during the years 2003–2005 were less than the $88 million carrying value of the plant as of December 31, 2002, SCE incurred an impairment charge of $61 million. However, in accordance with accounting standards for rate-regulated enterprises, this incurred cost was deferred and recorded as a regulatory asset, based on SCE's expectation that any unrecovered book value at the end of 2005 would be recovered in future rates through the rate-making mechanism discussed in its May 17, 2002 application and again in its January 30, 2003 supplemental testimony.

The outcome of SCE's application is not expected to impact Mohave's operation through 2005. Consequently, this matter has no impact on the timing of PROACT recovery.

Transmission and Distribution

This subsection of "SCE's Regulatory Matters" discusses the certain key regulatory proceedings.

PBR Decision

On April 22, 2002, the CPUC issued a decision that modified the PBR mechanism in the following significant respects:

- SCE's current PBR distribution sales mechanism was converted to a revenue requirement mechanism to prevent material revenue undercollections or overcollections resulting from errors in estimates of electric sales. A balancing account has been established to record any undercollections or overcollections, effective retroactively as of June 14, 2001.

- A methodology was adopted to set SCE's distribution revenue requirement for June 14 to December 31, 2001, calendar year 2002 and calendar year 2003 until replaced by the GRC. The methodology (a) established 2000 as the base year, (b) annually adjusts SCE's distribution revenue requirement by the change in the Consumer Price Index minus a productivity factor of 1.6%, and (c) annually increases SCE's distribution revenue requirement to account for additional costs of expanding the distribution network to connect new customers (an allowance of about $650 per customer).

- The performance benchmarks for worker safety, customer satisfaction and outage frequency have been updated effective in 2002 to reflect historical improvements in SCE's performance. These changes will reduce rewards SCE would earn compared to the previous standards.

As a result of this decision, in 2002, SCE recorded credits to earnings of approximately $26 million for revenue undercollections during the period June 14, 2001 through December 31, 2001 and credits to earnings of $73 million for the year ended December 31, 2002. All of these amounts are on an after-tax basis. This decision is incorporated into SCE's current projection of the timing of PROACT recovery.

2003 General Rate Case Proceeding

In December 2001, SCE submitted a notice of intent to file its 2003 GRC with the CPUC, requesting an increase of approximately $500 million in revenue (compared to 2000 recorded revenue) for its distribution and generation operations. On May 3, 2002, SCE filed its formal application for the 2003 GRC. After taking into account the effects of the CPUC's April 22, 2002 PBR decision, SCE requested a revenue requirement increase of $286 million. The requested revenue increase is primarily related to capital additions, updated depreciation costs and projected increases in pension and benefit expenses. In October 2002, the CPUC's Office of Ratepayer Advocates issued its testimony and recommended a $172 million decrease in SCE's base rates. Several other intervenors have also proposed further reductions to SCE's request or have made other substantive proposals regarding SCE's operations. Direct evidentiary hearings were concluded in January 2003. Rebuttal testimony has been filed and rebuttal hearings were held in late February 2003. A final decision is expected in the third quarter of 2003.

Cost of Capital Decision

On November 7, 2002, the CPUC issued a decision in SCE's cost of capital proceeding, adopting an 11.6% return on common equity for 2003 for SCE's CPUC jurisdictional assets. The 2003 cost of capital decision also established authorized costs for long-term debt and preferred stock, and established SCE's authorized rate-making capital structure for 2003 (although it does not apply during the PROACT recovery period), in addition to setting SCE's authorized return on common equity. This decision is incorporated into SCE's current projection of the timing of PROACT recovery.

Electric Line Maintenance Practices Proceeding

In August 2001, the CPUC issued an order instituting investigation (OII) regarding SCE's overhead and underground electric line maintenance practices. The OII is based on a report issued by the CPUC's Protection and Safety Consumer Services Division (CPSD), which alleges SCE had a pattern of noncompliance with the CPUC's General Orders for the maintenance of electric lines over the period

1998–2000. The OII also alleges that noncompliant conditions were "involved" in 37 accidents resulting in death, serious injury, or property damage. The CPSD identified 4,817 alleged violations of the General Orders during the three-year period. The OII placed SCE on notice that it is potentially subject to a penalty of between $500 and $20,000 for each violation or accident.

Prepared testimony was filed on this matter in April 2002 and hearings were concluded in September 2002. In opening briefs filed on October 21, 2002, the CPSD recommended SCE be assessed a penalty of $97 million, while SCE requested that the CPUC dismiss the proceeding and impose no penalties. SCE stated in its opening brief that it has acted reasonably, allocating its financial and human resources in pursuit of the optimum combination of employee and public safety, system reliability, cost-effectiveness, and technological advances. SCE also encouraged the CPUC to transfer consideration of issues related to development of standardized inspection methodologies and inspector training to an Order Instituting Rulemaking to revise these General Orders opened by the CPUC in October 2001, or to a new rulemaking proceeding. On March 14, 2003, SCE and the CPSD filed Opening Briefs in response to the assigned administrative law judge's direction to address application of the appropriate standard to govern SCE's electric line maintenance obligation. SCE described how both existing law and public policy favor SCE's implementation of cost-effective programs to inspect and maintain its electric system. The CPSD argued that, to avoid being found in violation and subject to penalty, all of SCE's overhead and underground lines and their components must be in compliance at all times. Oral arguments are scheduled for April 22, 2003. A decision is expected in the second or third quarter of 2003. SCE is unable to predict with certainty whether this matter ultimately will result in any material financial penalties or impacts on SCE.

Wholesale Electricity Markets

On April 25, 2001, after months of high power prices, the FERC issued an order providing for energy price controls during ISO Stage 1 or greater power emergencies (7% or less in reserve power). The order establishes an hourly clearing price based on the costs of the least efficient generating unit during the period. Effective June 20, 2001, the FERC expanded the April 25, 2001, order to include non-emergency periods and price mitigation in the 11-state western region through September 30, 2002. On July 17, 2002, the FERC issued an order reviewing the ISO's proposals to redesign the market and implementing a market power mitigation program for the 11-state western region. The FERC declined to extend beyond September 30, 2002 all of the market mitigation measures it had previously adopted. However, effective October 1, 2002, the FERC extended a requirement, first ordered in its June 19, 2001 decision, that all western energy sellers offer for sale all operationally and contractually available energy. It also ordered a cap on bids for real-time energy and ancillary services of $250/MWh to be effective beginning October 1, 2002, and ordered various other market power mitigation measures. Implementation of the $250/MWh bid cap and other market power mitigation measures were delayed until October 31, 2002 by a FERC order issued September 26, 2002. The FERC did not set a specific expiration date for its new market mitigation plan. SCE cannot yet determine whether the new market mitigation plan adopted by the FERC will be sufficient to mitigate market price volatility in the wholesale electricity markets in which SCE will purchase its residual net short electricity requirements (i.e., the amount of energy needed to serve SCE's customers from sources other than its own generating plants, power purchase contracts and CDWR contracts).

On August 2, 2000, SDG&E filed a complaint with the FERC seeking relief from alleged energy overcharges in the PX and ISO market. SCE intervened in the proceeding on August 14, 2000. On August 23, 2000, the FERC issued an order initiating an investigation of the justness and reasonableness of rates charged by sellers in the PX and ISO markets. Those proceedings were consolidated. On July 25, 2001, the FERC issued an order that limits potential refunds from alleged overcharges by energy suppliers to the ISO and PX spot markets during the period from October 2, 2000 through June 20, 2001, and adopted a refund methodology based on daily spot market gas prices. An administrative law judge conducted evidentiary hearings on this matter in March, August and October 2002 and issued and initial decision on December 12, 2002.

On November 20, 2002, in the consolidated proceeding, the FERC issued an order authorizing 100 days of discovery by market participants into market manipulation and abuse during the period January 1, 2000 through June 20, 2001. SCE joined with the California parties (PG&E, the California Attorney General, the Electricity Oversight Board, and the CPUC to submit briefs and evidence demonstrating that sellers and marketers violated tariffs, withheld power, and distorted and manipulated the California electricity markets.

At a FERC meeting on March 26, 2003, the FERC issued orders that initiated procedures for determining additional refunds arising from market manipulation by energy suppliers. Based on public comments at the meeting and the FERC's press releases, it appears that the FERC acknowledges that there was pervasive gaming and market manipulation of the electric and gas markets in California and on the west coast. A new FERC staff report issued on March 26, 2003 also describes many of the techniques and effects of electric and gas market manipulation. The FERC will be modifying the administrative law judge's initial decision of December 12, 2002 to reflect the fact that the gas indices used in the market manipulation formula overstated the cost of gas used to generate electricity.

SCE has not yet completed an evaluation of the FERC actions taken on March 26, 2003 and cannot determine the timing or amount of any potential refunds. Under the settlement agreement with the CPUC, any refunds will be applied to reduce the PROACT balance until the PROACT is fully recovered. After PROACT recovery is complete, 90% of any refunds will be refunded to ratepayers.

Other Regulatory Matters

This subsection of "SCE's Regulatory Matters" discusses an SCE plan to reduce customer rates after the PROACT has been fully recovered and the current status of the holding company proceeding.

Customer Rate-Reduction Plan

On January 17, 2003, SCE filed with the CPUC a detailed plan outlining how customer rates could be reduced later in 2003 when SCE expects to have completed recovery of uncollected procurement costs incurred on behalf of its customers during the California energy crisis and reflected in the PROACT. In its January 17, 2003 filing, SCE proposed that the CPUC apply rate reductions of about $1.3 billion in the same manner it applied a series of rate surcharges during the height of the energy crisis in 2001, primarily to rates paid by business and higher-use residential customers. If approved by the CPUC, after PROACT recovery is completed, bills for larger-use residential customers would decline 8%, and average rates would decline 19% for small and medium business customers and 26% for larger-use business customers. The CPUC has set a prehearing conference for March 21, 2003 and has asked for additional evidence on the effect on rates of applying the reductions on an equal cents-per-kilowatt-hour basis across all customer classes rather than as SCE has proposed. SCE cannot predict when the matter will be decided.

Holding Company Proceeding

In April 2001, the CPUC issued an OII that reopens the past CPUC decisions authorizing utilities to form holding companies and initiates an investigation into, among other things: whether the holding companies violated CPUC requirements to give first priority to the capital needs of their respective utility subsidiaries; 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. On January 9, 2002, the CPUC issued an interim decision on the first priority condition. The decision stated that, at least under certain circumstances, the condition includes the requirement that holding companies infuse all types of capital into their respective utility subsidiaries when necessary to fulfill the utility's obligation to serve. The decision did not determine if any of the utility holding companies had violated this condition, reserving such a determination for a later phase of the proceedings. On February 11, 2002, SCE and Edison International filed an application before the CPUC for rehearing of the decision. On July 17, 2002, the CPUC affirmed its earlier decision on the first priority condition and also denied Edison International's request for a rehearing of the CPUC's determination that it had jurisdiction over Edison International in this proceeding. On August 21, 2002, Edison International and SCE jointly filed a petition requesting a review of the CPUC's decisions with regard to first priority considerations, and Edison International filed a petition for a review of the CPUC decision asserting jurisdiction over holding companies, both in state court as required. PG&E, SDG&E and their respective holding companies filed similar challenges, and all cases have been transferred to the First District Court of Appeals in San Francisco. The CPUC filed briefs in opposition to the writ petitions. SCE, Edison International, and the other petitioners filed reply briefs on March 6, 2003. No hearings have been scheduled. The court may rule without holding hearings. Edison International cannot predict with certainty what effects this investigation or any subsequent actions by the CPUC may have on Edison International or any of its subsidiaries.

OTHER DEVELOPMENTS

Included in this section of the MD&A are developments regarding certain contingencies.

EME's Chicago In-City Obligation

Pursuant to the acquisition documents for the purchase of generating assets from Commonwealth Edison, EME committed to install one or more gas-fired electric generating units having an additional capacity of 500 MW at or adjacent to an existing power plant site in Chicago (this commitment being referred to as the In-City Obligation) for an estimated cost of $320 million . The acquisition documents required that commercial operation of this project commence by December 15, 2003. Due to additional capacity for new gas-fired generation and the improved reliability of power generation in the Chicago area, EME did not believe the additional gas-fired generation was needed. In February 2003, EME finalized an agreement with Commonwealth Edison to terminate this commitment in exchange for the following: payment of $22 million to Commonwealth Edison in February 2003; payment of approximately $14 million to Commonwealth Edison due in nine equal annual installments beginning in February 2004, secured by a security interest in 125,000 barrels of oil at the Collins Station; and assumption of power purchase obligation of the City of Chicago by entering into a replacement long-term power purchase contract with Calumet Energy Team LLC. The replacement contract requires EME to pay a monthly capacity payment and gives EME an option to purchase energy from Calumet Energy Team LLC at prices based primarily on operation and maintenance and fuel cost.

As a result of this agreement with Commonwealth Edison, EME's subsidiary recorded a before-tax loss of $45 million during the fourth quarter of 2002. The loss was determined by the sum of: (a) the present value of the cash payments to Commonwealth Edison and Calumet Energy Team LLC (capacity payments) less (b) the fair market value of the option to purchase power under the replacement contract with Calumet Energy Team LLC. As a result of this agreement with Commonwealth Edison, EME is no longer obligated to build the additional gas-fired generation.

Paiton Project

A wholly owned subsidiary of EME owns a 40% interest in Paiton Energy, which owns the Paiton project, a 1,230-MW coal-fired power plant in Indonesia. Under the terms of a long-term power purchase agreement between Paiton Energy and the state-owned electric utility company, the state-owned electric utility company is required to pay for capacity and fixed operating costs once each unit and the plant achieve commercial operation.

On December 23, 2002, an amendment to the original power purchase agreement became effective, bringing to a close and resolving a series of disputes between Paiton Energy and the state-owned electric utility that began in 1999 and were caused, in large part, by the effects of the regional financial crisis in Asia and Indonesia. The amended power purchase agreement includes changes in the price for power and energy charged under the power purchase agreement, provides for payment over time of amounts unpaid prior to January 2002 and extends the expiration date of the power purchase agreement from 2029 to 2040. These terms have been in effect since January 2002 under a previously agreed Binding Term Sheet, which was replaced by the power purchase agreement amendment.

In February 2003, Paiton Energy and all of its lenders concluded a restructuring of the project's debt. As part of the restructuring, the Export-Import Bank of the United States loaned the project $381 million, which was used to repay loans made by commercial banks during the period of the project's construction. In addition, the amortization schedule for repayment of the project's loans was extended to take into account the effect upon the project of the lower cash flow resulting from the restructured electricity tariff. The initial principal repayment under the new amortization schedule was made on February 18, 2003. Dividend distributions from the project to shareholders are not anticipated to commence until 2006. As a condition to the making of the loans by the Export-Import Bank of the United States, all commercial disputes related to the project were settled without a material effect on EME. EME believes that it will ultimately recover its investment in the project.

EME's investment in the Paiton project increased to $514 million at December 31, 2002, from $492 million at December 31, 2001. The increase in the investment account resulted from EME's subsidiary recording its proportionate share of net income from Paiton Energy. EME's investment in the Paiton project will increase or decrease from earnings or losses from Paiton Energy and decrease by cash distributions. Assuming Paiton Energy remains profitable, EME expects the investment account to increase substantially during the next several years as earnings are expected to exceed cash distributions.

During 2002, PT Batu Hitam Perkasa (BHP), one of the other shareholders in Paiton Energy, reinstated a previously suspended arbitration to resolve disputes under the fuel supply agreement between BHP and Paiton Energy. The arbitration commenced in 1999 but had been stayed since that time to allow the parties to engage in settlement discussions related to a restructuring of the coal supply arrangements for the Paiton project. These discussions did not at the time lead to settlement, and BHP requested an arbitration tribunal to reinstate the original arbitration and to permit BHP to assert additional claims. In total, BHP's claims amounted to $250 million.

On December 19, 2002, Paiton Energy and BHP entered into an agreement in which all claims in the arbitration were settled and agreement was reached to dismiss the arbitration with no material effect upon Paiton Energy. Paiton Energy made the required payment to BHP under the terms of the settlement agreement and all claims have been dismissed.

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

As further discussed in Note 10 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 at SCE (41 sites) and EME (3 sites) is $101 million, $99 million of which is related to SCE. The sites include SCE's divested gas-fueled generation plants, for which SCE retained some liability after their sale. 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 $284 million, $282 million of which is related to SCE.

The CPUC allows SCE to recover environmental-cleanup costs at certain sites, representing $38 million of its recorded liability, through an incentive mechanism, which is discussed in Note 10. SCE has recorded a regulatory asset of $70 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 $15 million to $25 million. Recorded costs for 2002 were $25 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.

In 1999, SCE and other co-owners of the Mohave plant entered into a consent decree to resolve a federal court lawsuit that had been filed alleging violations of various emissions limits. This decree, approved by the court in December 1999, required certain modifications to the plant in order for it to continue to operate beyond 2005.

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).

SCE's share of the costs of complying with the consent decree and taking other actions to continue operation of the Mohave station beyond 2005 is estimated to be approximately $605 million over the next four years. This amount is included in the $2.0 billion for Edison International's projected environmental capital expenditure (discussed below). SCE has received from the State of Nevada a permit to construct the necessary controls. However, SCE has suspended its efforts to seek CPUC approval to install the Mohave controls because it has not obtained reasonable assurance of adequate coal and water supplies for operating Mohave beyond 2005. Unless adequate coal and water supplies are obtained, it will become necessary to shut down the Mohave station after December 31, 2005. If the station is shut down at that time, the shutdown is not expected to have a material adverse impact on SCE's financial position or results of operations, assuming the remaining book value of the station (approximately $27 million as of December 31, 2002) and the related regulatory asset (approximately $61 million as of December 31, 2002), and plant closure and decommissioning-related costs are recoverable in future rates. SCE cannot predict, with certainty, what effect any future actions by the CPUC may have on this matter. See "SCE's Regulatory Matters—Mohave Generating Station Proceeding" for further discussion of the Mohave issues.

EME expects that compliance with the Clean Air Act will result in increased capital expenditures and operating expenses. EME anticipates the cost of upgrades to environmental controls to be about $30 million for the period 2003–2007. This amount is included in the $2.0 billion for Edison International's projected environmental capital expenditures (discussed below). In addition, EME has entered into a coal cleaning agreement related to its Homer City plant, which includes a fixed fee and variable component based on tons of coal processed.

Edison International's projected environmental capital expenditures are $2.0 billion for the 2003–2007 period, mainly for undergrounding certain transmission and distribution lines at SCE and upgrading environmental controls at EME.

Electric and Magnetic Fields

Electric and magnetic fields (EMFs) naturally result from the generation, transmission, distribution and use of electricity. Since the 1970s, concerns have been raised about the potential health effects of EMFs. After 30 years of research, no health hazard has been established. Many of the questions about specific diseases have been successfully resolved due to an aggressive international research program. Potentially important public health questions remain about whether there is a link between EMF exposures in homes or work and some diseases, including childhood leukemia and a variety of other adult diseases (e.g., adult cancers and miscarriages), and because of these questions, some health authorities have identified magnetic field exposures as a possible human carcinogen.

In October 2002, the California Department of Health Services (CDHS) released its report evaluating the possible risks from electric and magnetic fields (CDHS Report) to the CPUC and the public. The CDHS

Report's conclusions contrast with other recent reports by authoritative health agencies in that the CDHS has assigned a substantially higher probability to the possibility that there is a causal connection between EMF exposures and a number of diseases and conditions, including childhood leukemia, adult leukemia, amyotrophic lateral sclerosis, and miscarriages.

This report concludes a program initiated by the CPUC's 1993 Interim EMF Decision. Under the policies advanced by that decision, utilities have already committed to funding research, providing education materials to employees and customers, and taking proactive steps to lower magnetic fields from new facilities.

It is not yet clear what actions the CPUC will take to respond to the CDHS Report and to the recent EMF reports by other health authorities such as the National Institute of Environmental Health Sciences, the World Health Organization's International Agency for Research on Cancer, and the United Kingdom's National Radiation Protection Board. Possible outcomes include, but are not limited to, continuation of current policies and imposition of more stringent policies to implement greater reductions in EMF exposures. The costs of these different outcomes are unknown at this time.

Navajo Nation Litigation

Peabody Holding Company (Peabody) supplies coal from mines on Navajo Nation lands to Mohave. In June 1999, the Navajo Nation filed a complaint in federal district court against Peabody and certain of its affiliates, Salt River Project Agricultural Improvement and Power District, and SCE. The complaint asserts claims against the defendants for, among other things, violations of the federal RICO statute, interference with fiduciary duties and contractual relations, fraudulent misrepresentation by nondisclosure, and various contract-related claims. The complaint claims that the defendants' actions prevented the Navajo Nation from obtaining the full value in royalty rates for the coal. The complaint seeks damages of not less than $600 million, trebling of that amount, and punitive damages of not less than $1 billion, as well as a declaration that Peabody's lease and contract rights to mine coal on Navajo Nation lands should be terminated.

In February 2002, Peabody and SCE filed cross claims against the Navajo Nation, alleging that the Navajo Nation had breached a settlement agreement and final award between Peabody and the Navajo Nation by filing their lawsuit.

The Navajo Nation had previously filed suit in the Court of Claims against the United States Department of Interior, alleging that the Government had breached its fiduciary duty concerning contract negotiations including the Navajo Nation and the defendants. In February 2000, the Court of Claims issued a decision in the Government's favor, finding that while there had been a breach, there was no available redress from the Government. Following appeal of that decision by the Navajo Nation, an appellate court ruled that the Court of Claims did have jurisdiction to award damages and remanded the case to the Court of Claims for that purpose. On June 3, 2002, the Government's request for review of the case by the United States Supreme Court was granted. On March 4, 2003, the Supreme Court reversed the appellate court and held that the Government is not liable to the Navajo Nation as there was no breach of a fiduciary duty.

SCE cannot predict with certainty the outcome of the 1999 Navajo Nation's complaint against SCE, nor the impact on this complaint or the Supreme Court's decision on the outcome of the Navajo Nation's suit against the Government, or the impact of the complaint on the operation of Mohave beyond 2005.

Employee Compensation and Benefit Plans

Edison International measures compensation expense related to stock-based compensation by the intrinsic value method. If Edison International were to adopt the fair-value method of accounting and charge the cost of the stock options to expense, effective with stock options granted in 2002, earnings for the year ended December 31, 2002 would have been reduced by approximately $2 million, based on a Black-Scholes option-pricing model.

Under accounting standards for pension costs, if the accumulated benefit obligation (ABO) exceeds the market value of plan assets at the measurement date, the difference may result in a reduction to shareholders' equity through a charge to other comprehensive income. As of December 31, 2002, the $147 million in ABO for three of Edison International's pension plans, measured using a discount rate that represented the market interest rate for high quality fixed income investments, exceeded the market value of the related pension plan assets, resulting in an $21 million (net of tax) reduction to shareholders' equity. As of December 31, 2002, the $2.4 billion in ABO of all other pension plans (95% of which are at SCE) was approximately $120 million less than the market value of the related plan assets, resulting in no additional reduction to shareholders' equity. For these remaining plans, a reduction of shareholders' equity may be required at the next measurement date in December 2003, depending on such factors as the discount rate, plan asset rate of return experience and contributions made by Edison International in 2003. See additional discussion in "Critical Accounting Policies—Pensions."

San Onofre Inspection

SCE's San Onofre Unit 2 returned to service on July 2, 2002 after a 43-day outage for scheduled refueling and maintenance. SCE's San Onofre Unit 3 returned to service on February 17, 2003 after a 42-day outage for scheduled refueling and maintenance. During these outages, detailed inspections of the reactor vessel head nozzle penetrations were conducted. The subject of reactor vessel head nozzle penetrations has received industry attention recently due to the leakage from such nozzles at the Davis Besse nuclear plant in Ohio. The inspections conducted at San Onofre Units 2 and 3 found no indications of leakage or degradation in the reactor vessel head nozzle penetrations.

Federal Income Taxes

On August 7, 2002, Edison International received a notice from the IRS asserting deficiencies in federal corporate income taxes for Edison International's 1994 to 1996 tax years. Substantially all of the tax deficiencies are timing differences and, therefore, amounts ultimately paid, if any, would benefit Edison International as future tax deductions. Edison International is challenging the deficiencies asserted by the IRS. Edison International believes that it has meritorious legal defenses to those deficiencies and believes that the ultimate outcome of this matter will not result in a material impact on Edison International's consolidated results of operations or financial position.

Among the issues raised by the IRS in the 1994 through 1996 audit was Edison Capital's treatment of the EPZ and Dutch electric locomotive leases. Written protests were filed against these deficiency notices, as well as other alleged deficiencies, asserting that the IRS's position misstates material facts, misapplies the law and is incorrect. Edison Capital will vigorously contest the assessment through administrative appeals and litigation, if necessary, and believes it should ultimately prevail.

The IRS is also currently examining the tax returns for Edison International, which includes Edison Capital, for years 1997 through 1999. Edison Capital expects the IRS to also challenge several of its other leveraged leases based on a recent Revenue Ruling addressing a specific type of leverage lease termed a lease in/lease out or LILO transaction. Edison Capital believes that the position described in the Revenue Ruling is incorrect and that its leveraged leases are factually and legally distinguishable in material respects from that position. Edison Capital intends to vigorously defend, and litigate, if necessary, against any challenges based on the position in the recent Revenue Ruling.

Edison International is, and may in the future be, under examination by tax authorities in varying tax jurisdictions with respect to positions Edison International takes in connection with the filing of its tax returns. Matters raised upon audit may involve substantial amounts, which, if resolved unfavorably, an event not currently anticipated, could possibly be material. However, in Edison International's opinion, it is unlikely that the resolution of any such matters will have a material adverse effect upon Edison International's financial condition or results of operations.

OFF-BALANCE SHEET TRANSACTIONS

This section of the MD&A discusses off-balance sheet transactions at EME and Edison Capital. SCE does not have any off-balance sheet transactions. Included are discussions of investments accounted for under the equity method for both subsidiaries, as well as sale-leaseback transactions at EME, EME's obligations to one of its subsidiaries, and leveraged leases at Edison Capital.

EME's Off-Balance Sheet Transactions

EME has off-balance sheet transactions in two principal areas: investments in projects accounted for under the equity method and operating leases resulting from sale-leaseback transactions.

Investments Accounted for under the Equity Method

Investments in which EME has a 50% or less ownership interest are accounted for under the equity method in accordance with and as required by current accounting standards. Under the equity method, the project assets and related liabilities are not consolidated in Edison International's consolidated balance sheet. Rather, Edison International's financial statements reflect its investment in each entity and it records only its proportionate ownership share of net income or loss. These investments are of three principal categories.

Historically, EME has invested in so-called qualifying facilities, that is, those which produce electric energy and steam, or other forms of useful energy, and which otherwise meet the requirements set forth in the Public Utility Regulatory Policies Act. These regulations limit EME's ownership interest in qualifying facilities to no more than 50% due to EME's affiliation with SCE, a public utility. For this reason, EME owns a number of domestic energy projects through partnerships in which it has a 50% or less ownership interest.

On an international basis, for purposes of risk mitigation, EME has often invested in energy projects with strategic partners where its ownership interest is 50% or less.

EME owns a minority interest in Four Star Oil & Gas Company, an oil and gas company that provides a natural hedge of a portion of the fuel price risk associated with its merchant power plants.

Entities formed to own these projects are generally structured with a management committee or board of directors in which EME exercises significant influence but cannot exercise unilateral control over the operating, funding or construction activities of the project entity. EME's energy projects have generally secured long-term debt to finance the assets constructed and/or acquired by them. These financings generally are secured by a pledge of the assets of the project entity, but do not provide for any recourse to EME. Accordingly, a default on a long-term financing of a project could result in foreclosure on the assets of the project entity resulting in a loss of some or all of EME's project investment, but would generally not require EME to contribute additional capital. At December 31, 2002, entities which EME has accounted for under the equity method had indebtedness of $6 billion, of which $3 billion is proportionate to EME's ownership interest in these projects. See "New Accounting Standards" for further discussion.

Sale-Leaseback Transactions

EME has entered into sale-leaseback transactions related to the Collins, Powerton and Joliet plants in Illinois and the Homer City facilities in Pennsylvania. Each of these transactions was completed and accounted for according to an accounting standard, which requires, among other things, that all of the risk and rewards of ownership of assets be transferred to a new owner without continuing involvement in the assets by the former owner other than as normal for a lessee. These transactions were entered into to provide a source of capital either to fund the original acquisition of the assets or to repay indebtedness previously incurred for the acquisition. In each of these transactions, the assets (or, in the case of the Collins Station, the rights to purchase them) were sold to and then leased from owner/lessors owned by independent equity investors. In addition to the equity invested in them, these owner/lessors incurred or assumed long-term debt, referred to as lessor debt, to finance the purchase of the assets. In the case of Powerton and Joliet and Homer City, the lessor debt takes the form generally referred to as secured lease obligation bonds. In the case of Collins, the lessor debt takes the form of lessor notes as described in the footnote to the table below.

EME's subsidiaries account for these leases as financings in their separate financial statements due to specific guarantees provided by EME or another one its subsidiaries as part of the sale-leaseback transactions. These guarantees do not preclude EME from recording these transactions as operating leases in its consolidated financial statements, but constitute continuing involvement under the accounting standard that precludes EME's subsidiaries from utilizing this accounting treatment in their separate subsidiary financial statements. Instead, each subsidiary continues to record the power plants as assets in a similar manner to a capital lease and records the obligations under the leases as lease financings. EME's subsidiaries, therefore, record depreciation expense from the power plants and interest expense from the lease financing in lieu of an operating lease expense, which EME uses in preparing its consolidated financial statements. The treatment of these leases as an operating lease in its consolidated financial statements in lieu of a lease financing, which is recorded by EME's subsidiaries, results in an increase in EME's consolidated net income by $89 million, $55 million and $40 million in 2002, 2001 and 2000, respectively.

The lessor equity and lessor debt associated with the sale-leaseback transactions for the Collins, Powerton, Joliet and Homer City assets are summarized in the following table as of December 31, 2002:

In millions	Acquisition Price	Equity Investor	Equity Investment in Owner/Lessor	Amount of Lessor Debt	Maturity Date of Lessor Debt
Power Station(s):					
Collins	$ 860	PSEG	$ 117	$ 774	(i)
Powerton/Joliet	1,367	PSEG/	238	333.5	2009
		Citicapital		813.5	2016
Homer City	1,591	GECC	798	300	2019
				530	2026

PSEG – PSEG Resources, Inc.
GECC – General Electric Capital Corporation

(i) The owner/lessor under the Collins lease issued notes in the amount of the lessor debt to Midwest Funding LLC, a funding vehicle created and controlled by the owner/lessor. These notes mature in January 2014 and are referred to as the lessor notes. Midwest Funding LLC, in turn, entered into a commercial paper and loan facility with a group of banks pursuant to which it borrowed the funds required for its purchase of the lessor notes. These borrowings are currently scheduled to mature in December 2004 and are referred to as the lessor borrowings.

The rent under the Collins lease includes both a fixed component and a variable component, which is affected by movements in defined interest rate indices. If the lessor borrowings are not repaid at maturity, by a refinancing or otherwise, the interest rate on them would increase at specified increments every three months, which would be reflected in adjustments to the Collins lease rent payments. EME's subsidiary lessee under the Collins lease may request the owner/lessor to cause Midwest Funding LLC to refinance the lessor borrowings in accordance with guidelines set forth in the lease, but such refinancing is subject to the owner/lessor's approval. If the lessor borrowings are not refinanced by December 2004 because the owner/lessor's approval is not obtained or a refinancing is not commercially available, rent under the Collins lease would increase by approximately $9 million for the first quarter of 2005 and increase approximately $2 million for each quarter thereafter.

The operating lease payments to be made by each of EME's subsidiary lessees are structured to service the lessor debt and provide a return to the owner/lessor's equity investors. Neither the value of the leased assets nor the lessor debt is reflected in EME's consolidated balance sheet. In accordance with generally accepted accounting principles, EME records rent expense on a levelized basis over the terms of the respective leases. To the extent that EME's cash rent payments exceed the amount levelized over the term of each lease, EME records prepaid rent. At December 31, 2002 and 2001, prepaid rent on these leases was $117 million and $21 million, respectively. To the extent that EME's cash rent payments are less than the amount levelized, EME reduces the amount of prepaid rent.

In the event of a default under the leases, each lessor can exercise all of its rights under the applicable lease, including repossessing the power plant and seeking monetary damages. Each lease sets forth a termination value payable upon termination for default and in certain other circumstances, which generally declines over time and in the case of default may be reduced by the proceeds arising from the sale of the repossessed power plant. A default under the terms of the Collins, Powerton and Joliet or Homer City leases could result in a loss of EME's ability to use such power plant and would trigger obligations under EME's guarantee of the Powerton and Joliet leases. These events could have a material adverse effect on EME's results of operations and financial position.

Total minimum lease payments during the next five years are $311 million in 2003, $291 million in 2004, $343 million in 2005, $427 million in 2006 and $465 million in 2007. At December 31, 2002, the minimum lease payments due after 2007 were $4.9 billion.

EME's Obligations to Midwest Generation, LLC

The proceeds, in the aggregate amount of approximately $1.4 billion, received by Midwest Generation from the sale of the Powerton and Joliet plants, described above under "—Sale-leaseback Transactions", were loaned to EME. EME used the proceeds from this loan to repay corporate indebtedness. Although interest and principal payments made by EME to Midwest Generation under this intercompany loan assist in the payment of the lease rental payments owing by Midwest Generation, the intercompany obligation does not appear on Edison International's consolidated balance sheet. This obligation has been disclosed to the credit rating agencies at the time of the transaction and has been included by them in assessing EME's credit ratings. The principal payments due under this intercompany loan during the next five years are $1 million in 2003 and 2004, $2 million in 2005 and $3 million in 2006 and 2007.

EME funds the interest and principal payments due under this intercompany loan from distributions from EME's subsidiaries, including Midwest Generation, cash on hand and amounts available under corporate lines of credit. A default by EME in the payment of this intercompany loan could result in a shortfall of cash available for Midwest Generation to meet its lease and debt obligations. A default by Midwest Generation in meeting its obligations could, in turn, have a material adverse effect on EME.

Edison Capital's Off-Balance Sheet Transactions

Edison Capital has entered into off-balance sheet transactions for investments in projects, which, in accordance with generally accepted accounting principles, do not appear on Edison International's balance sheet.

Investments Accounted for under the Equity Method

Partnership investments, in which Edison Capital does not have operational control or significant voting rights, are accounted for under the equity method as required by accounting standards. As such, the project assets and liabilities are not consolidated on the balance sheet; rather, the financial statements reflect the carrying amount of the investment and the proportionate ownership share of net income or loss.

Edison Capital has invested in affordable housing projects utilizing partnership or limited liability companies in which Edison Capital is a limited partner or limited liability member. In these entities, Edison Capital usually owns a 99% interest. With a few exceptions, an unrelated general partner or managing member exercises operating control; voting rights of Edison Capital are limited by agreement to certain high level matters. The debt of those partnerships and limited liability companies is secured by real property and is non-recourse to Edison Capital, except in limited cases where Edison Capital has guaranteed the debt. At December 31, 2002, Edison Capital had made guarantees to lenders in the amount of $2.4 million. Edison Capital has subsequently sold a majority of these interests to unrelated third party investors through syndication partnerships in which Edison Capital has retained an interest, with one exception, of less than 20%.

Beginning in 1999, Edison Capital invested in four wind projects. As of December 31, 2002, Edison Capital owned 75% ownership interest in three of the projects and 99% interest in the fourth project. In each of these projects, once Edison Capital receives its target return specified by agreement, Edison Capital's percentage interest drops below 50% for that project.

The entities formed to own these wind projects are generally governed by a management committee or board of directors in which Edison Capital exercises significant influence but cannot exercise unilateral control over the operating, funding or construction activities of the project entity. The entities have generally obtained long-term debt to finance the construction or acquisition of the assets. This debt is generally secured by a pledge of the assets, but the lenders have no recourse to Edison Capital beyond the investment made in the projects. Edison Capital has also provided a debt service reserve guarantee of approximately $8 million to one of the projects. In any event, a default on a long-term debt for a project could result in foreclosure on the assets of the project entity resulting in a loss of some or all of Edison Capital's project investment, but Edison Capital is not required to contribute additional capital.

At December 31, 2002, entities that Edison Capital has accounted for under the equity method had indebtedness of $1.7 billion, of which approximately $534 million is proportionate to Edison Capital's ownership interest in these projects. Substantially all of this debt is non-recourse to Edison Capital.

Leveraged Leases

Edison Capital is the lessor in various power generation, electric transmission and distribution, transportation and telecommunications leases. The debt in these leveraged leases is non-recourse to Edison Capital and is not recorded on Edison International's balance sheet in accordance with the applicable accounting standards.

At December 31, 2002, Edison Capital had investments of $2.3 billion in its leveraged leases, with non-recourse debt in the amount of $5 billion.

DISCONTINUED OPERATIONS

During fourth quarter 2002, events related to EME's Lakeland project resulted in an impairment charge of $92 million ($77 million after tax) and a provision for bad debts of $1 million, after tax, arising from the write-down of the Lakeland power plant and related claims under the power sales agreement to their fair market value. Due to EME's loss of control arising from the appointment of the administrative receiver, EME no longer consolidates the activities of Lakeland Power Ltd.

On December 21, 2001, EME completed the sale of the Ferrybridge and Fiddler's Ferry coal stations located in the U.K. for an aggregate sale price of £643 million (approximately $945 million). Included in the loss from discontinued operations in 2001 is a loss on sale of $1.9 billion ($1.1 billion after tax). Net proceeds from the sale were used to repay borrowings outstanding under the existing debt facility related to the acquisition of the power plants. In addition to the charge discussed above, the early repayment of the project's existing debt facility of £682 million (approximately $1.0 billion) at December 21, 2001, resulted in a loss of $28 million (after tax) attributable to the write-off of unamortized debt issuance costs.

In August 2001, Edison Enterprises, a wholly owned subsidiary of Edison International, sold a subsidiary principally engaged in the business of providing residential security services and residential electrical warranty repair services. On October 18, 2001, Edison Enterprises completed the sale of substantially all of the assets of another subsidiary (engaged in the business of commercial energy management) to the subsidiary's current management. Included in the loss from discontinued operations in 2001 is a loss on sale of $127 million (after tax) related to these transactions.

The results of the coal stations and Edison Enterprises' subsidiaries sold during 2001 have been reflected as discontinued operations in the consolidated financial statements, in accordance with a recently issued and adopted accounting standard related to the impairment and disposal of long-lived assets. The consolidated financial statements have been restated to conform to the discontinued operations presentation for all years presented. The pre-tax losses of the discontinued operations were $2.2 billion in 2001, $34 million in 2000 and $111 million in 1999.

ACQUISITIONS AND DISPOSITIONS

On March 3, 2003, EME's Contact Energy completed a transaction with NGC Holdings Ltd. to acquire the Taranaki Combined Cycle power station and related interests for NZ$500 million ($280 million). The NZ$500 million purchase price was financed with bridge loan facilities. Contact Energy intends to refinance these facilities with the issuance of long-term senior debt. The Taranaki station is a 357 MW combined cycle, natural gas-fired plant located near Stratford, New Zealand.

During the first quarter of 2002, EME completed the sales of its 50% interests in the Commonwealth Atlantic and James River projects and its 30% interest in the Harbor project. Proceeds received from the sales were $44 million. During the second half of 2001, EME recorded asset impairment charges of $33 million related to these projects based on the expected sales proceeds. No gain or loss was recorded from the sale of EME's interests in these projects during the first quarter of 2002.

CRITICAL ACCOUNTING POLICIES

The accounting policies described below are viewed by management as critical because their application is the most relevant and material to Edison International's results of operations and financial position and these policies require the use of material judgments and estimates.

Asset Impairment

Edison International evaluates long-lived assets whenever indicators of potential impairment exist. Accounting standards require that if the undiscounted expected future cash flow from a company's assets or group of assets is less than its carrying value, an asset impairment must be recognized in the financial statements. The amount of impairment is determined by the difference between the carrying amount and fair value of the asset.

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

During the fourth quarter of 2002, SCE assessed the impairment of its Mohave plant due to the probability of a plant shutdown at the end of 2005. Because the expected undiscounted cash flows from the plant during the years 2003–2005 were less than the $88 million carrying value of the plant as of December 31, 2002, SCE incurred an impairment charge of $61 million. However, in accordance with accounting principles for rate regulated companies, this incurred cost was deferred and recorded as a regulatory asset, due to the expectation that the unrecovered book value of Mohave at the time of shutdown will be recovered through the rate-making process. See "SCE's Regulatory Matters—Mohave Generating Station Proceeding" and "—Rate Regulated Enterprises."

During the fourth quarter of 2002, EME assessed the impairment of its Illinois plants. EME has grouped the Illinois plants into two asset groups: coal-fired power plants and the small peaker plants. Management judgment was required to make this assessment based on the lowest level of cash flow that was viewed by management as largely independent of each other. The expected future undiscounted cash flow from EME's merchant power plants is a critical accounting estimate because: (1) estimating future prices of energy and capacity in wholesale energy markets is susceptible to significant change, (2) the period of the forecast is over an extended period of time due to the estimated useful life (15 to 33 years) of power plants, and (3) the impact of an impairment on Edison International's consolidated financial position and results of operations could be material. The expected undiscounted future cash flow from the Illinois plants exceeded the carrying value of those asset groups.

During the fourth quarter of 2002, an impairment charge of $92 million ($77 million after tax) was recorded related to EME's Lakeland power plant due to the change in financial condition of TXU Europe and its subsidiaries, one of which was a counterparty to a long-term power purchase agreement (considered an indicator of impairment under the accounting standard). Management's judgment was required to determine the asset group, which was determined as the power plant and claim under the power purchase agreement. Furthermore, a management estimate was required to determine the fair value of the asset group as the expected undiscounted future cash flow was less that the carrying value of the asset. See "Discontinued Operations and Dispositions," for further discussion.

Edison International also would record an impairment charge if a decision is made (which generally occurs when Edison International enters into an agreement to sell an asset) to dispose of an asset and the fair value is less than Edison International's book value. Using this type of analysis, EME recorded a $1.9 billion impairment of EME's Ferrybridge and Fiddler's Ferry power plants during the third quarter of 2001 and $127 million for the majority of the Edison Enterprises companies in 2001. See "Discontinued Operations and Dispositions," for further discussion.

EME operates several power plants under leases as described below under "Off-Balance Sheet Financing." Under generally accepted accounting principles as currently interpreted, EME is not required to record a loss if future cash flows from use of an asset under lease are less than the expected minimum lease payments. This accounting issue has been discussed in an authoritative accounting interpretation for the recognition by a purchaser of losses on firmly committed executory contracts, without reaching a consensus. Future minimum lease payments on EME's Collins Station are estimated to be $1.4 billion. As a result, if the accounting guidance in this area were to change, EME could be required to record a loss on this lease, depending on an assessment of future expected cash flow at the time such guidance was changed.

Due to lower wholesale prices for energy during 2002 (see "—Market Risk Exposures—EME's Market Risks—Commodity Price Risk"), EME has suspended operations of four units at the Illinois plants (Units 1 and 2 at Will County and Units 4 and 5 at the Collins Station). EME also suspended operations during 2002 at three units at First Hydro, two of which had resumed operations by December 2002. EME continues to record depreciation on such assets during the period that EME has suspended operations. Accounting for these units as idle facilities requires management's judgment that these units will return to service. EME has continued the maintenance of these units in order to return them to service when market conditions improve on a sustained basis and future environmental uncertainties are resolved. If market conditions do not improve on a sustained basis, environmental uncertainties are not resolved or are resolved unfavorably, or if a decision is made not to return them to service due to other factors, EME could sell or decommission one or more of these units. Such a decision could result in a loss on sale or a write-down of the carrying value of these assets.

EME evaluates goodwill whenever indicators of impairment exist, but at least annually on October 1 of each year. EME has recorded goodwill associated with three acquisitions: Contact Energy, First Hydro and Citizens Power LLC. EME determined through a fair value analysis conducted by third parties that the fair value of the Contact Energy and First Hydro reporting units was in excess of book value. Accordingly, no impairment of the goodwill related to these reporting units was recorded upon adoption of this standard. EME concluded that, based on fair value of a comparable transaction, the fair value of the reporting unit related to the Citizens Power LLC acquisition was less than its book value. Accordingly, a goodwill impairment of $14 million, net of $9 million of income tax benefits was recorded. In accordance with the goodwill and other intangible accounting standard, the impairment as of January 1, 2002 is recorded as a cumulative effect of a change in accounting principle in EME's consolidated income statement.

Determining the fair value of the reporting unit under the goodwill and other intangible accounting standard is a critical accounting estimate because: (1) it is susceptible to change from period to period since it requires assumptions regarding future revenues and costs of operations and discount rates over an indefinite life, and (2) the impact of recognizing an impairment on EME's consolidated financial position and results of operations would be material. EME has engaged third parties to conduct appraisals of the fair value of the major reporting units with goodwill on October 1, 2002 (the annual impairment testing date). The fair value of the First Hydro and Contact Energy reporting units set forth in these appraisals exceeded their book value.

Derivative Financial Instruments and Hedging Activities

Edison International follows the accounting standard for derivative instruments and hedging activities, which requires derivative financial instruments to be recorded at their fair value unless an exception applies. The accounting standard also requires that changes in a derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. For derivatives that qualify for hedge accounting, depending on the nature of the hedge, changes in fair value are either offset by changes in the fair value of the hedged assets, liabilities or firm commitments through earnings, or recognized in other comprehensive income until the hedged item is recognized in earnings. The ineffective portion of a derivative's change in fair value is immediately recognized in earnings.

EME uses derivative financial instruments for price risk management activities and trading purposes. Derivative financial instruments are mainly utilized to manage exposure from changes in electricity and fuel prices, interest rates and fluctuations in foreign currency exchange rates.

Management's judgment is required to determine if a transaction meets the definition of a derivative and whether the normal sales and purchases exception applies or whether individual transactions qualify for hedge accounting treatment. The majority of EME's power sales and fuel supply agreements related to its generation activities either: (1) do not meet the definition of a derivative as they are not readily convertible to cash, (2) qualify as normal purchases and sales and are, therefore, recorded on an accrual basis or (3) qualify for hedge accounting.

Derivative financial instruments used at EME for trading purposes includes forwards, futures, options, swaps and other financial instruments with third parties. EME records at fair value derivative financial instruments used for trading. The majority of EME's derivative financial instruments with a short-term duration (less than one year) are valued using quoted market prices. In the absence of quoted market prices, derivative financial instruments are valued at fair value, considering time value of money, volatility of the underlying commodity, and other factors as determined by EME. Resulting gains and losses are recognized in net gains (losses) from price risk management and energy trading in the accompanying consolidated income statements in the period of change. Assets from price risk management and energy trading activities include the fair value of open financial positions related to derivative financial instruments recorded at fair value, including cash flow hedges, that are in-the-money and the present value of net amounts receivable from structured transactions. Liabilities from price risk management and energy trading activities include the fair value of open financial positions related to derivative financial instruments, including cash flow hedges, that are out-of-the-money and the present value of net amounts payable from structured transactions.

Determining the fair value of derivatives under this accounting standard is a critical accounting estimate because the fair value of a derivative is susceptible to significant change resulting from a number of factors, including volatility of energy prices, credits risks, market liquidity and discount rates. See "—Market Risk Exposures," for a description of risk management activities and sensitivities to change in market prices.

EME enters into master agreements and other arrangements in conducting price risk management and trading activities with a right of setoff in the event of bankruptcy or default by the counterparty. Such transactions are reported net in the balance sheet in accordance with an authoritative interpretation for offsetting amounts related to certain contracts.

Income Taxes

The accounting standard for income taxes requires the asset and liability approach for financial accounting and reporting for deferred income taxes. Edison International uses the asset and liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences.

As part of the process of preparing its consolidated financial statements, Edison International is required to estimate its income taxes in each of the jurisdictions in which it operates. This process involves estimating actual current tax expense together with assessing temporary differences resulting from differing treatment of items, such as depreciation, for tax and accounting purposes. These differences result in deferred tax assets and liabilities, which are included within Edison International's consolidated balance sheet. Edison International does not provide for federal income taxes or tax benefits on the undistributed earnings or losses of its international subsidiaries because such earnings are reinvested indefinitely. Management continually evaluates its income tax exposures and provides for allowances and/or reserves as deemed necessary.

Off-Balance Sheet Financing

EME has entered into sale-leaseback transactions related to the Collins, Powerton and Joliet plants in Illinois and the Homer City facilities in Pennsylvania. (See "Off-Balance Sheet Transactions—EME's Off-Balance Sheet Transactions—Sale-Lease Transactions.") Each of these transactions was completed and accounted for by EME as an operating lease in its consolidated financial statements in accordance with the accounting standard for sale-leaseback transactions involving real estate, which requires, among other things, that all of the risk and rewards of ownership of assets be transferred to a new owner without continuing involvement in the assets by the former owner other than as normal for a lessee. Completion of sale-leaseback transactions of these power plants is a complex matter involving management judgment to determine compliance with the provisions of the accounting standards, including the transfer of all the risk and rewards of ownership of the power plants to the new owner without EME's continuing involvement other than as normal for a lessee. These transactions were entered into to provide a source of capital either to fund the original acquisition of the assets or to repay indebtedness previously incurred for the acquisition. Each of these leases uses special purpose entities.

Based on existing accounting guidance, EME does not record these lease obligations in its consolidated balance sheet. If these transactions were required to be consolidated as a result of future changes in accounting guidance, it would: (1) increase property, plant and equipment and long-term obligations in the consolidated financial position, and (2) impact the pattern of expense recognition related to these obligations as EME would likely change from its current straight-line recognition of rental expense to an annual recognition of the straight-line depreciation on the leased assets as well as the interest component of the financings which is weighted more heavily toward the early years of the obligations. The difference in expense recognition would not affect EME's cash flows under these transactions. See "Off-Balance Sheet Transactions."

Edison Capital has entered into lease transactions, as lessor, related to various power generation, electric transmission and distribution, transportation and telecommunications assets. All of the debt under Edison Capital's leveraged leases is non-recourse and is not recorded on Edison International's balance sheet in accordance with the applicable accounting standards.

Partnership investments, in which Edison International owns a percentage interest and does not have operational control or significant voting rights, are accounted for under the equity method as required by accounting standards. As such, the project assets and liabilities are not consolidated on the balance sheet. Rather, the financial statements reflect only the proportionate ownership share of net income or loss. See "Off-Balance Sheet Transactions."

Pensions

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

The discount rate enables Edison International to state expected future cash flows at a present value on the measurement date. At the December 31, 2002 measurement date, Edison International used a discount rate of 6.5% that represented the market interest rate for high-quality fixed income investments.

To determine the expected long-term rate of return on pension plan assets, current and expected asset allocations are considered, as well as historical and expected returns on plan assets. The expected rate of return on plan assets was 8.5%. Actual return on plan assets resulted in losses in the pension trusts of $331 million in 2002. However, accounting principles provide that differences between expected and actual returns are recognized over the average future service of employees.

At December 31, 2002, Edison International's pension plans included $2.8 billion in projected benefit obligation (PBO), $2.3 billion in ABO and $2.4 billion in plan assets. A 1% decrease in the discount rate would increase the PBO by $210 million, and a 1% increase would decrease the PBO by $194 million, with corresponding changes in the ABO. A 1% decrease in the expected rate of return on plan assets would decrease pension expense by $26 million.

SCE accounts for about 95% of Edison International's total pension obligation, and 98% of its assets held in trusts, at December 31, 2002. SCE records pension expense equal to the amount funded to the trusts, as calculated using an actuarial method required for rate-making purposes, in which the impact of market volatility on plan assets is recognized in earnings on a more gradual basis. Any difference between pension expense calculated in accordance with rate-making methods and pension expense or income calculated in accordance with accounting standards is accumulated in a regulatory asset or liability, and will, over time, be recovered from or returned to ratepayers. As of December 31, 2002, this cumulative difference amounted to a regulatory liability of $185 million, meaning that the rate-making method has resulted in recognizing $185 million more in expense than the accounting method since implementation of the pension accounting standard in 1987.

Under accounting standards, if the ABO exceeds the market value of plan assets at the measurement date, the difference may result in a reduction to shareholders' equity through a charge to other comprehensive income, but would not affect current net income. The reduction to other comprehensive income would be restored through shareholders' equity in future periods to the extent the market value of trust assets exceeded the ABO.

Rate Regulated Enterprises

SCE applies accounting principles for rate-regulated enterprises to the portion of its operations, in which regulators set rates at levels intended to recover the estimated costs of providing service, plus a return on capital. Due to timing and other differences in the collection of revenue, these principles allow an incurred cost that would otherwise be charged to expense by a non-regulated entity to be capitalized as a regulatory asset if it is probable that the cost is recoverable through future rates and conversely allow creation of a regulatory liability for probable future costs collected through rates in advance. SCE's management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as the current regulatory environment, the issuance of rate orders on recovery of the specific incurred cost or a similar incurred cost to SCE or other rate-regulated entities in California, and assurances from the regulator (as well as its primary intervenor groups) that the incurred cost will be treated as an allowable cost (and not challenged) for rate-making purposes. Because current rates include the recovery of existing regulatory assets and settlement of regulatory liabilities, and rates in effect are expected to allow SCE to earn a reasonable rate of return, management believes that existing regulatory assets and liabilities are probable of recovery. This determination reflects the current political and regulatory climate in California and is subject to change in the future. If future recovery of costs ceases to be probable, all or part of the regulatory assets and liabilities would have to be written off against current period earnings. At December 31, 2002, the Consolidated Balance Sheets included regulatory assets, less regulatory liabilities, of $4.3 billion. Management continually evaluates the anticipated recovery of regulatory assets, liabilities, and revenue subject to refund and provides for allowances and/or reserves as deemed necessary.

SCE applied judgment in the use of the above principles when: it concluded, as of December 31, 2000, that $4.2 billion of generation-related regulatory assets and liabilities were no longer probable of recovery, and wrote off these assets as a charge to earnings, in fourth quarter 2001; it created the $3.6 billion PROACT regulatory asset, in second quarter 2002; it restored $480 million (after-tax) of generation-related regulatory assets based on the URG decision; in fourth quarter 2002, it established a $61 million regulatory asset related to the impaired Mohave plant. In all instances, SCE recorded corresponding credits to earnings upon concluding that such incurred costs were probable of recovery in the future.

See further discussion in "Results of Operations—Earnings (Loss) from Continuing Operations" and "SCE's Regulatory Matters—PROACT Regulatory Asset, —URG Decision, and —Mohave Generating Station Proceeding" sections.

NEW ACCOUNTING STANDARDS

On January 1, 2001, Edison International adopted a new accounting standard for derivative instruments and hedging activities. An authoritative accounting interpretation issued in October 2001 precludes fuel contracts that have variable amounts from qualifying under the normal purchases and sales exception effective April 1, 2002. The adoption of this interpretation did not have a significant impact on Edison International's financial statements. Under a revised authoritative accounting interpretation issued in December 2001, EME's forward electricity contracts no longer qualify for the normal sales exception since EME has net settlement provisions with its counterparties. However, these contracts qualify as cash flow hedges. Edison International implemented the December 2001 interpretation, effective April 1, 2002. As a result, Edison International recorded a $6 million increase to other comprehensive income as the cumulative effect of adoption of this interpretation.

In October 2002, an accounting interpretation related to accounting for contracts involved in energy trading and risk management activities was rescinded. The rescission means that energy trading and risk management activities will be no longer be recorded at fair value as trading activities, but instead will follow accounting standards for derivative instruments and hedging activities, in which each energy contract must be assessed to determine whether or not it meets the definition of a derivative. If an energy contract meets the definition of a derivative, then it would be recorded at fair value (i.e., marked-to-market), subject to permitted exceptions. If an energy contract does not meet the definition of a derivative, then it would be recorded on an accrual basis. Edison International does not expect this interpretation to have a material impact on its consolidated financial statements.

On January 1, 2002, Edison International adopted a new accounting standard for Goodwill and Other Intangibles. The new accounting standard required a benchmark assessment for goodwill by June 30, 2002. Edison International has completed its benchmark assessment and has determined that no goodwill impairment exists, except for goodwill related to EME's September 2000 acquisition of Citizens Power. Total goodwill related to Citizens Power was $25 million as of December 31, 2001. In accordance with the new accounting standard, during third quarter 2002, an additional test was performed to determine the amount of the impairment. The result of this test was a $23 million ($14 million after tax) goodwill impairment associated with the Citizens Power acquisition. The cumulative effect of a change in accounting principle was recorded in the other nonoperating deductions line item of the December 31, 2002, consolidated statements of income (loss), retroactive to January 1, 2002.

In November 2002, an accounting interpretation was issued which establishes reporting requirements to be made by a guarantor about its obligations under certain guarantees that it has issued. It also clarifies that a guarantor is required to recognize, at the inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. The initial recognition and initial measurement provisions of this interpretation are applicable on a prospective basis to guarantees issued or modified after December 31, 2002. The disclosure requirements of this interpretation are effective for Edison International's December 31, 2002 Note disclosures. See "Commitments—Guarantees and Indemnities."

Effective January 1, 2003, Edison International will adopt a new accounting standard, Accounting for Asset Retirement Obligations, which requires entities to record the fair value of a liability for a legal asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the entity capitalizes the cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is increased to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement. However, rate-regulated entities may recognize regulatory assets or liabilities as a result of timing differences between the recognition of costs as recorded in accordance with this statement and costs recovered through the rate-making process. Regulatory assets and liabilities may be recorded when it is probable that the asset retirement costs will be recovered through the rate-making process.

Edison International's estimates the impact of adopting this standard will be as follows:

- SCE will adjust its nuclear decommissioning obligation to reflect the fair value of decommissioning its nuclear power facilities. SCE will also recognize asset retirement obligations associated with the decommissioning of other coal-fired generation assets.

- At December 31, 2002, the total nuclear decommissioning obligation accrued for SCE's active nuclear facilities was $2.0 billion and is included in accumulated provision for depreciation and decommissioning on the consolidated balance sheets. SCE has accrued, at December 31, 2002, $12 million to decommission certain coal-fired generation assets based on its estimate of the decommissioning obligation under the accounting principles in effect at that time. These decommissioning obligations are included in accumulated provision for depreciation on the consolidated balance sheets.

- SCE estimates that it will record a $190 million decrease to its recorded nuclear and coal facility decommissioning obligations for asset retirement obligations in existence as of January 1, 2003. The estimated cumulative effect of a change in accounting principle from unrecognized accretion expense and adjustments to depreciation, decommissioning and amortization expense accrued to date is a $408 million gain (pre-tax), which will be reflected as a regulatory liability as of January 1, 2003.

- EME expects to record a cumulative effect adjustment effective January 1, 2003 that will decrease net income by approximately $10 million, after tax.

In January 2003, an accounting interpretation was issued to address consolidation of variable interest entities. The primary objective of the interpretation is to provide guidance on the identification of, and financial reporting for, entities over which control is achieved through means other than voting rights; such entities are known as variable interest entities (VIEs). This interpretation applies to VIEs created after January 31, 2003, and applies to VIEs in which an enterprise holds a variable interest that it acquired before February 1, 2003, beginning July 1, 2003.

Under this interpretation, if an enterprise absorbs the majority of the VIE's expected losses or receives a majority of the VIE's expected residual returns, or both, it must consolidate the VIE. An enterprise that is required to consolidate the VIE is called the primary beneficiary. Additional disclosure requirements are also applicable when an enterprise holds a significant variable interest in a VIE, but is not the primary beneficiary. In addition, financial statements issued after January 31, 2003 must include certain disclosures if it is reasonably possible that an enterprise will consolidate or disclose information about a VIE when this interpretation is effective.

EME has concluded that it is the primary beneficiary of its Brooklyn Navy Yard project since it is at risk with respect to the majority of its losses and is entitled to receive the majority of its residual returns. Accordingly, EME will consolidate Brooklyn Navy Yard, effective July 1, 2003. EME expects the consolidation of this entity to increase total assets by approximately $365 million and total liabilities by approximately $445 million. EME expects to record a loss of up to $80 million as a cumulative change of accounting as a result of consolidating this variable interest entity. This loss is primarily due to cumulative losses allocated to the other 50% partner in excess of equity contributions recorded.

EME believes it is reasonably possible that certain partnership interests in energy projects and interests in non-utility generators are VIEs under this interpretation, as discussed below:

EME owns certain partnership interests in seven energy partnerships, which own a combined 3,098 MW of power plants. These partnerships generally sell the electricity under power purchase agreements that expire at various dates through 2039. The maximum exposure to loss from EME's interest in these entities is $1.1 billion at December 31, 2002. Of this amount, $541 million represents EME's investment in the 1,230 MW Paiton project and $307 million represents EME's investment in the 540 MW EcoEléctrica project.

EME owns a 50% interest in TM Star, which was formed for the limited purpose to sell natural gas to March Point Cogeneration Company under a fuel supply agreement. TM Star has entered into fuel purchase contracts with unrelated third parties to meet a portion of the obligations under the fuel supply agreement. EME has guaranteed 50% of the obligation under the fuel supply agreement to March Point Congestion Company. The maximum loss is subject to changes in natural gas prices. Accordingly, the maximum exposure to loss cannot be determined.

FORWARD-LOOKING INFORMATION AND RISK FACTORS

In the preceding MD&A and elsewhere in this annual report, the words estimates, expects, anticipates, believes, predict, and other similar expressions are intended to identify forward-looking information that involves risks and uncertainties. Actual results or outcomes could differ materially from those anticipated. Risks, uncertainties and other important factors that could cause results to differ or that otherwise could impact Edison International and its subsidiaries, include, among other things:

- the outcome of the pending appeal of the stipulated judgment approving SCE's settlement agreement with the CPUC, and the effects of other legal actions, if any, attempting to undermine the provisions of the settlement agreement or otherwise adversely affecting SCE;

- the substantial amount of debt and lease obligations of MEHC, EME and their subsidiaries, including $911 million of debt maturing in December 2003 and $275 million of a credit facility expiring in September 2003, which presents the risk that MEHC, EME, and their subsidiaries might not be able to repay or refinance their obligations, raise additional financing for their future cash requirements, or provide credit support for ongoing operations;

- the actions of securities rating agencies, including the determination of whether or when to make changes in ratings assigned to Edison International and its subsidiaries that are rated, the ability of Edison International, SCE, EME and Edison Capital to regain investment-grade ratings, and the impact of current or lowered ratings and other financial market conditions on the ability of the respective companies to obtain needed financing on reasonable terms and provide credit support;

- changes in prices and availability of wholesale electricity, natural gas, other fuels, and transmission services, and other changes in operating costs, which could affect the timing of SCE's energy procurement cost recovery, or otherwise impact SCE's and EME's operations and financial results;

- the operation of some of EME's power plants without long-term power purchase agreements, which may adversely affect EME's ability to sell the plant's output at profitable terms;

- the substantial amount of EME's revenue derived under power purchase agreements with a single customer, which could adversely affect EME's results of operations and liquidity;

- changing conditions in wholesale power markets, such as general credit constraints and thin trading volumes, that could make it difficult for EME or SCE to buy or sell power or enter into hedging agreements;

- provisions in MEHC's, EME's and their subsidiaries' organizational and financing documents that limit their ability to, among other things, incur and repay debt, pay dividends, sell assets, and enter into specified transactions that they otherwise might enter into, which may impair their ability to compete effectively or to operate successfully under adverse economic conditions;

- the possibility that existing tax allocation agreements may be terminated or may not operate as contemplated, for example, if the consolidated group does not have sufficient taxable income to use the tax benefits of each group member, or if any member ceases to be a part of the consolidated group;

- actions by state and federal regulatory and administrative bodies setting rates, adopting or modifying cost recovery, holding company rules, accounting and rate-setting mechanisms, or otherwise changing the regulatory and business environments within which Edison International and its subsidiaries do business, as well as legislative or judicial actions affecting the same matters;

- the effects of increased competition in energy-related businesses, including new market entrants and the effects of new technologies that may be developed in the future;

- threatened attempts by municipalities within SCE's service territory to form public power entities and/or acquire SCE's facilities for customers;

- the credit worthiness and financial strength of Edison Capital's counterparties worldwide in energy and infrastructure projects, including power generation, electric transmission and distribution, transportation, and telecommunications;

- the effects of declining interest rates and investment returns on employee benefit plans and nuclear decommissioning trusts;

- general political, economic and business conditions in the countries in which EIX and its subsidiaries do business;

- political and business risks of doing business in foreign countries, including uncertainties associated with currency exchange rates, currency repatriation, expropriation, political instability, privatization and other issues;

- power plant operation risks, including equipment failures, availability, output and labor issues;

- new or increased environmental requirements that could require capital expenditures or otherwise affect the operations and cost of Edison International and its subsidiaries, and possible increased liabilities under new or existing requirements; and

- weather conditions, natural disasters, and other unforeseen events.

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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 accountants, PricewaterhouseCoopers 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 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 accountants (who are ultimately accountable to the board and the committee) to conduct audits of Edison International's 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 its 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

March 26, 2003

To the Board of Directors and Shareholders of Edison International:

In our opinion, the accompanying consolidated balance sheet and the related consolidated statements of income (loss), comprehensive income (loss), changes in common shareholders' equity, and cash flows present fairly, in all material respects, the financial position of Edison International and its subsidiaries at December 31, 2002, and the results of their operations and their cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion. The financial statements of the Company as of December 31, 2001, and for each of the two years in the period ended December 31, 2001, were audited by other independent accountants who have ceased operations. Those independent accountants expressed an unqualified opinion on those financial statements and included an explanatory paragraph that described the change in method of accounting for derivative instruments and hedging activities and method of accounting for the impairment of long-lived assets discussed in Note 1 to the financial statements in their report dated March 25, 2002.

/s/ PricewaterhouseCoopers LLP

Los Angeles, California
March 26, 2003

THE FOLLOWING REPORT IS A COPY OF A REPORT PREVIOUSLY ISSUED BY ARTHUR ANDERSEN LLP AND HAS NOT BEEN REISSUED BY ARTHUR ANDERSEN LLP

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, 2001, and 2000, and the related consolidated statements of income (loss), comprehensive income (loss), cash flows and common shareholders' equity for each of the three years in the period ended December 31, 2001. 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, 2001, and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

As explained in Note 1 to the financial statements, effective January 1, 2001, Edison International has changed its method of accounting for derivative instruments and hedging activities in accordance with SFAS 133, "Accounting for Derivative Instruments and Hedging Activities," and its method of accounting for the impairment or disposal of long-lived assets in accordance with SFAS 144, "Accounting for the Impairment or Disposal of Long-lived Assets."

Arthur Andersen LLP

Los Angeles, California
March 25, 2002

Consolidated Statements of Income (Loss)			**Edison International**
In millions, except per-share amounts Year ended December 31,	**2002**	2001	2000
Electric utility	**$ 8,705**	$ 8,120	$ 7,870
Nonutility power generation	**2,750**	2,594	2,294
Financial services and other	**33**	348	260
Total operating revenue	**11,488**	11,062	10,424
Fuel	**1,186**	1,128	1,004
Purchased power	**2,016**	3,770	4,687
Provisions for regulatory adjustment clauses – net	**1,502**	(3,028)	2,301
Other operation and maintenance	**3,242**	3,029	2,619
Depreciation, decommissioning and amortization	**1,030**	973	1,784
Property and other taxes	**145**	114	129
Net gain on sale of utility plant	**(5)**	(6)	(25)
Total operating expenses	**9,116**	5,980	12,499
Operating income (loss)	**2,372**	5,082	(2,075)
Interest and dividend income	**287**	282	209
Equity in income from partnerships and unconsolidated subsidiaries – net	**249**	343	247
Other nonoperating income	**93**	108	162
Interest expense – net of amounts capitalized	**(1,283)**	(1,582)	(1,257)
Other nonoperating deductions	**(77)**	(70)	(122)
Dividends on preferred securities	**(96)**	(92)	(100)
Dividends on utility preferred stock	**(19)**	(22)	(22)
Income (loss) from continuing operations before taxes	**1,526**	4,049	(2,958)
Income tax (benefit)	**391**	1,647	(1,019)
Income (loss) from continuing operations	**1,135**	2,402	(1,939)
Loss from discontinued operations (including loss on disposal of $1,309, net of tax, in 2001)	**(74)**	(2,223)	(34)
Income tax (benefit) on discontinued operations	**(16)**	(856)	(30)
Net income (loss)	**$ 1,077**	$ 1,035	$ (1,943)
Weighted-average shares of common stock outstanding	**326**	326	333
Basic earnings (loss) per share:			
Continuing operations	**$ 3.49**	$ 7.37	$ (5.83)
Discontinued operations	**(0.18)**	(4.19)	(0.01)
Total	**$ 3.31**	$ 3.18	$ (5.84)
Weighted-average shares, including effect of dilutive securities	**328**	326	333
Diluted earnings (loss) per share:			
Continuing operations	**$ 3.46**	$ 7.36	$ (5.83)
Discontinued operations	**(0.18)**	(4.19)	(0.01)
Total	**$ 3.28**	$ 3.17	$ (5.84)
Dividends declared per common share	**$ —**	$ —	$ 0.84

Consolidated Statements of Comprehensive Income (Loss)

In millions Year ended December 31,	**2002**	2001	2000
Net income (loss)	**$ 1,077**	$ 1,035	$ (1,943)
Other comprehensive income, net of tax:			
Foreign currency translation adjustments	**125**	6	(150)
Minimum pension liability adjustment	**(21)**	—	—
Unrealized loss on investments – net	**(9)**	—	(7)
Cumulative effect of change in accounting for derivatives	**6**	148	—
Unrealized loss on cash flow hedges – net	**(20)**	(359)	—
Reclassification adjustment for gain (loss) included in net income (loss)	**—**	16	(24)
Comprehensive income (loss)	**$ 1,158**	$ 846	$ (2,124)

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

Consolidated Balance Sheets

In millions December 31,	2002	2001
ASSETS		
Cash and equivalents	**$ 2,474**	$ 3,991
Receivables, less allowances of $49 and $41 for uncollectible accounts at respective dates	**1,111**	1,259
Accrued unbilled revenue	**437**	451
Fuel inventory	**124**	124
Materials and supplies, at average cost	**225**	203
Accumulated deferred income taxes – net	**270**	1,092
Trading and price risk management assets	**34**	65
Regulatory assets – net	**509**	83
Prepayments and other current assets	**274**	232
Total current assets	**5,458**	7,500
Nonutility property – less accumulated provision for depreciation of $924 and $706 at respective dates	**6,923**	6,414
Nuclear decommissioning trusts	**2,210**	2,275
Investments in partnerships and unconsolidated subsidiaries	**2,011**	2,253
Investments in leveraged leases	**2,313**	2,386
Other investments	**235**	226
Total investments and other assets	**13,692**	13,554
Utility plant, at original cost		
Transmission and distribution	**14,202**	13,568
Generation	**1,457**	1,729
Accumulated provision for depreciation and decommissioning	**(8,094)**	(7,969)
Construction work in progress	**529**	556
Nuclear fuel, at amortized cost	**153**	129
Total utility plant	**8,247**	8,013
Goodwill	**661**	633
Regulatory assets – net	**3,838**	5,528
Other deferred charges	**1,327**	1,341
Total deferred charges	**5,826**	7,502
Assets of discontinued operations	**61**	205
Total assets	**$ 33,284**	$ 36,774

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

In millions, except share amounts December 31,	2002	2001
LIABILITIES AND SHAREHOLDERS' EQUITY		
Short-term debt	**$ 78**	$ 2,445
Long-term debt due within one year	**2,761**	1,499
Preferred stock to be redeemed within one year	**9**	105
Accounts payable	**866**	3,414
Accrued taxes	**855**	183
Trading and risk management liabilities	**45**	24
Other current liabilities	**2,040**	2,187
Total current liabilities	**6,654**	9,857
Long-term debt	**11,557**	12,674
Accumulated deferred income taxes – net	**5,842**	6,367
Accumulated deferred investment tax credits	**167**	172
Customer advances and other deferred credits	**1,841**	1,675
Power-purchase contracts	**309**	356
Accumulated provision for pensions and benefits	**461**	505
Other long-term liabilities	**161**	147
Total deferred credits and other liabilities	**8,781**	9,222
Liabilities of discontinued operations	**72**	71
Commitments and contingencies (Notes 2, 9 and 10)		
Minority interest	**425**	345
Preferred stock of utility:		
Not subject to mandatory redemption	**129**	129
Subject to mandatory redemption	**147**	151
Company-obligated mandatorily redeemable securities of subsidiaries holding solely parent company debentures	**951**	949
Other preferred securities	**131**	104
Total preferred securities of subsidiaries	**1,358**	1,333
Common stock (325,811,206 shares outstanding at each date)	**1,973**	1,966
Accumulated other comprehensive loss	**(247)**	(328)
Retained earnings	**2,711**	1,634
Total common shareholders' equity	**4,437**	3,272
Total liabilities and shareholders' equity	**$ 33,284**	$ 36,774

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

Consolidated Statements of Cash Flows — Edison International

In millions Year ended December 31,	2002	2001	2000
Cash flows from operating activities:			
Net income (loss) from continuing operations	**$ 1,135**	$ 2,402	$ (1,939)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, decommissioning and amortization	**1,030**	973	1,784
Other amortization	**113**	92	168
Deferred income taxes and investment tax credits	**160**	1,908	(1,080)
Equity in income from partnerships and unconsolidated subsidiaries	**(249)**	(343)	(247)
Income from leveraged leases	**(6)**	(154)	(192)
Regulatory assets – long-term – net	**1,860**	(3,135)	1,759
Write-down of nonutility assets	**—**	245	—
Gas call options	**14**	(91)	20
Net gain on sale of marketable securities	**—**	—	(57)
Other assets	**89**	(51)	20
Other liabilities	**170**	(134)	(107)
Changes in working capital:			
Receivables and accrued unbilled revenue	**193**	(47)	(159)
Regulatory assets – short-term – net	**(426)**	(278)	97
Fuel inventory, materials and supplies	**(11)**	(16)	30
Prepayments and other current assets	**(11)**	203	79
Accrued interest and taxes	**523**	(240)	185
Accounts payable and other current liabilities	**(2,674)**	1,551	797
Distributions and dividends from unconsolidated entities	**337**	236	227
Operating cash flows from discontinued operations	**80**	(147)	19
Net cash provided by operating activities	**2,327**	2,974	1,404
Cash flows from financing activities:			
Long-term debt issued	**409**	3,386	5,293
Long-term debt repaid	**(1,784)**	(1,761)	(4,495)
Bonds remarketed (repurchased) and funds held in trust – net	**191**	(130)	(440)
Issuance of preferred securities	**—**	104	—
Redemption of preferred securities	**(100)**	(164)	(125)
Common stock repurchased	**—**	—	(386)
Rate reduction notes repaid	**(246)**	(246)	(246)
Nuclear fuel financing – net	**(59)**	(21)	9
Short-term debt financing – net	**(956)**	(1,547)	1,296
Dividends to minority shareholders	**(37)**	—	—
Dividends paid	**—**	—	(371)
Financing cash flows from discontinued operations	**(19)**	(1,178)	223
Net cash provided (used) by financing activities	**(2,601)**	(1,557)	758
Cash flows from investing activities:			
Additions to property and plant – net	**(1,590)**	(933)	(1,426)
Purchase of nonutility generation plant	**—**	—	(47)
Purchase of power sales agreement	**(80)**	—	—
Proceeds from sale of nonutility property	**62**	1,032	1,727
Net funding of nuclear decommissioning trusts	**(12)**	(36)	(69)
Distributions from (investments in) partnerships and unconsolidated subsidiaries	**42**	(122)	(289)
Proceeds from sales of marketable securities	**—**	—	58
Net investments in leveraged leases	**—**	68	(255)
Sales of investments in other assets	**247**	(433)	(275)
Investing cash flows from discontinued operations	**2**	1,125	(89)
Net cash provided (used) by investing activities	**(1,329)**	701	(665)
Effect of exchange rate changes on cash	**23**	(37)	(32)
Net increase (decrease) in cash and equivalents	**(1,580)**	2,081	1,465
Cash and equivalents, beginning of year	**4,054**	1,973	508
Cash and equivalents, end of year	**2,474**	4,054	1,973
Cash and equivalents – discontinued operations	**—**	(63)	(369)
Cash and equivalents – continuing operations	**$ 2,474**	$ 3,991	$ 1,604

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

In millions, except share amounts	Common Stock	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Common Shareholders' Equity
Balance at December 31, 1999	$ 2,090	$ 42	$ 3,079	$ 5,211
Net loss			(1,943)	(1,943)
Stock repurchase and retirement (21,402,700 shares)	(130)		(257)	(387)
Dividends declared on common stock			(277)	(277)
Unrealized loss on investment		(11)		(11)
Tax effect		4		4
Reclassified adjustment for loss included in net income		(41)		(41)
Tax effect		17		17
Foreign currency translation adjustments		(148)		(148)
Tax effect		(2)		(2)
Stock option appreciation			(3)	(3)
Balance at December 31, 2000	$ 1,960	$(139)	$ 599	$ 2,420
Net income			1,035	1,035
Foreign currency translation adjustments		(1)		(1)
Tax effect		7		7
Unrealized loss on cash flow hedges		(296)		(296)
Tax effect		(63)		(63)
Reclassified adjustment for gain included in net income		24		24
Tax effect		(8)		(8)
Cumulative effect of change in accounting for derivatives		24		24
Tax effect		124		124
Stock option appreciation and other	6			6
Balance at December 31, 2001	$ 1,966	$(328)	$ 1,634	$ 3,272
Net income			1,077	1,077
Foreign currency translation adjustments		128		128
Tax effect		(3)		(3)
Minimum pension liability adjustment		(29)		(29)
Tax effect		8		8
Unrealized loss on investment		(14)		(14)
Tax effect		5		5
Cumulative effect of change in accounting for derivatives		12		12
Tax effect		(6)		(6)
Unrealized loss on cash flow hedges		(22)		(22)
Tax effect		2		2
Stock option appreciation and other	7			7
Balance at December 31, 2002	$ 1,973	$ (247)	$ 2,711	$ 4,437

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

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

Notes to Consolidated Financial Statements

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

Note 1. Summary of Significant Accounting Policies

Edison International's principal wholly owned subsidiaries include: Southern California Edison Company (SCE), a rate-regulated electric utility that supplies electric energy to a 50,000 square-mile area of central, coastal and southern California; Edison Mission Energy (EME), a producer of electricity engaged in the development and operation of electric power generation facilities worldwide; Edison Capital, a provider of capital and financial services; and Mission Energy Holding Company (MEHC), a holding company for EME. 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, partially mitigating the effects of regional markets, economic downturns or unusual weather conditions. EME's domestic facilities (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. A plant in Australia sells its energy and capacity production through a centralized power pool. A plant in the United Kingdom sells its energy production by entering into physical bilateral contracts with various counterparties. Other electric power generated overseas is sold under short- and long-term contracts to electricity companies, electricity buying groups or electric utilities located in the country where the power is generated. EME also conducts energy trading and price risk management activities in power markets open to competition.

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 of the significant voting rights. Intercompany transactions have been eliminated, except EME's profits from energy sales to SCE, which are allowed in utility rates. EME's equity in income from energy projects and oil and gas investments was reclassified from nonutility power generation revenue to equity in income from partnerships and unconsolidated subsidiaries – net in the 2001 and 2000 income statements to make the presentation consistent with the current years' presentation. Except as indicated, amounts presented in the Notes to the Consolidated Financial Statements relate to continuing operations.

SCE's accounting policies conform to accounting principles generally accepted in the United States, including the accounting principles for rate-regulated enterprises, which reflect the rate-making policies of the California Public Utilities Commission (CPUC) and the Federal Energy Regulatory Commission (FERC). In 1997, due to changes in the rate-recovery of generation-related assets, SCE began using accounting principles applicable to enterprises in general for its investment in generation facilities. In April 2002, SCE reapplied accounting principles for rate-regulated enterprises to assets that were returned to cost-based regulation under the utility-retained generation (URG) decision (see "URG Proceeding" in Note 2).

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 Notes. Actual results could differ from those estimates. Certain significant estimates related to electric utility regulatory matters, financial instruments, decommissioning and contingencies are further discussed in Notes 2, 3, 9 and 10 to the Consolidated Financial Statements, respectively.

Cash Equivalents

Cash equivalents include time deposits and other investments with original maturities of three months or less. All investments are classified as available for sale. For a discussion of restricted cash, see "Restricted Cash".

Debt and Equity 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 except for San Onofre Nuclear Generating Station (San Onofre) Unit 1, which is recorded against the related regulatory asset. All investments are classified as available-for-sale.

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. Dilutive securities are excluded from the diluted EPS calculation during periods of net loss due to their antidilutive effect.

Fuel Inventory

SCE's fuel 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.

Goodwill

Goodwill represents the excess of cost incurred over the fair value of net assets acquired in a purchase transaction. Goodwill was amortized on a straight-line basis over periods ranging from 20 to 40 years. On January 1, 2002, the amortization of goodwill ceased upon adoption of a new accounting standard. See "New Accounting Standards" for a further discussion.

Impairment of Investments and Long-Lived Assets

In fourth quarter 2001, Edison International adopted early an accounting standard for the impairment or disposal of long-lived assets. Edison International evaluates the long-lived assets whenever indicators of impairment exist. This accounting standard requires that if the undiscounted expected future cash flow from a company's assets or group of assets (without interest charges) is less than its carrying value, an asset impairment must be recognized in the financial statements. The amount of the impairment is determined by the difference between the carrying amount and fair value of the asset.

New Accounting Standards

On January 1, 2001, Edison International adopted a new accounting standard for derivative instruments and hedging activities. An authoritative accounting interpretation issued in October 2001 precludes fuel contracts that have variable amounts from qualifying under the normal purchases and sales exception effective April 1, 2002. The adoption of this interpretation did not have a significant impact on Edison International's financial statements. Under a revised authoritative accounting interpretation issued in December 2001, EME's forward electricity contracts no longer qualify for the normal sales exception since EME has net settlement provisions with its counterparties. However, these contracts qualify as cash flow hedges. Edison International implemented the December 2001 interpretation, effective April 1, 2002. As a result, Edison International recorded a $6 million increase to other comprehensive income as the cumulative effect of adoption of this interpretation.

In October 2002, an accounting interpretation related to accounting for contracts involved in energy trading and risk management activities was rescinded. The rescission means that energy trading and risk management activities will no longer be recorded at fair value as trading activities, but instead will follow accounting standards for derivative instruments and hedging activities, where each energy contract must be assessed to determine whether or not it meets the definition of a derivative. If an energy contract meets the definition of a derivative, it would be recorded at fair value (i.e., marked-to-market), subject to permitted exceptions. If an energy contract does not meet the definition of a derivative, it would be recorded on an accrual basis. Edison International does not expect this interpretation to have a material impact on its consolidated financial statements.

On January 1, 2002, Edison International adopted a new accounting standard for Goodwill and Other Intangibles. The new accounting standard required a benchmark assessment for goodwill by June 30, 2002. Edison International has completed its benchmark assessment and has determined that no goodwill impairment exists, except for goodwill related to EME's September 2000 acquisition of Citizens Power. Total goodwill related to Citizens Power was $25 million as of December 31, 2001. In accordance with the new accounting standard, during third quarter 2002 an additional test was performed to determine the amount of the impairment. The result of this test was a $23 million ($14 million after tax) goodwill impairment (excess carrying amount of the goodwill over its implied fair value) associated with the Citizens Power acquisition. Estimates of fair value were determined using comparable transactions. The cumulative effect of a change in accounting principle was recorded in the other nonoperating deductions line item of the December 31, 2002, consolidated statements of income (loss), retroactive to January 1, 2002.

In November 2002, an accounting interpretation was issued that establishes reporting requirements to be made by a guarantor about its obligations under certain guarantees that it has issued. It also clarifies that a guarantor is required to recognize, at the inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. The initial recognition and measurement provisions of this interpretation are applicable on a prospective basis to guarantees issued or modified after December 31, 2002. The disclosure requirements of this interpretation are effective for Edison International's December 31, 2002 Note disclosures. A discussion of Edison International's guarantees and indemnities is in Note 9.

Effective January 1, 2003, Edison International will adopt a new accounting standard, Accounting for Asset Retirement Obligations, which requires entities to record the fair value of a liability for a legal asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the entity capitalizes the cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is increased to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement. However, rate-regulated entities may recognize regulatory assets or liabilities as a result of timing differences between the recognition of costs as recorded in accordance with this statement and costs recovered through the rate-making process. Regulatory assets and liabilities may be recorded when it is probable that the asset retirement costs will be recovered through the rate-making process.

Edison International estimates the impact of adopting this standard will be as follows:

- SCE will adjust its nuclear decommissioning obligation to reflect the fair value of decommissioning its nuclear power facilities. SCE will also recognize asset retirement obligations associated with the decommissioning of other coal-fired generation assets.

- At December 31, 2002, the total nuclear decommissioning obligation accrued for SCE's active nuclear facilities was $2.0 billion and is included in accumulated provision for depreciation and decommissioning on the consolidated balance sheets. SCE has accrued, at December 31, 2002, $12 million to decommission certain coal-fired generation assets based on its estimate of the decommissioning obligation under the accounting principles in effect at that time. These decommissioning obligations are also included in accumulated provision for depreciation and decommissioning on the consolidated balance sheets.

- SCE estimates that it will record a $190 million decrease to its recorded nuclear and coal facility decommissioning obligations for asset retirement obligations in existence as of January 1, 2003. The estimated cumulative effect of a change in accounting principle from unrecognized accretion expense and adjustments to depreciation, decommissioning and amortization expense accrued to date is a $408 million gain (pre-tax), which will be reflected as a regulatory liability as of January 1, 2003.

- EME expects to record a cumulative effect adjustment effective January 1, 2003 that will decrease net income by approximately $10 million, after tax.

In January 2003, an accounting interpretation was issued to address consolidation of variable-interest entities (VIEs). The primary objective of the interpretation is to provide guidance on the identification of, and financial reporting for, entities over which control is achieved through means other than voting rights; such entities are known as VIEs. This interpretation applies to VIEs created after January 31, 2003 and beginning July 1, 2003 applies to VIEs in which an enterprise holds a variable interest that it acquired before February 1, 2003. See Note 11 for a discussion of Edison International's VIE's.

Nuclear

During the second quarter of 1998, SCE reduced its remaining nuclear plant investment by $2.6 billion (book value 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. The reclassification had no effect on SCE's 1998 results of operations.

SCE had been recovering its investments in San Onofre Units 2 and 3 and Palo Verde Nuclear Generating Station (Palo Verde) 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, were recovered through an incentive pricing plan that allows SCE to receive about 4¢ per kilowatt-hour through 2003. Any differences between these costs and the incentive price would flow through to shareholders. Palo Verde's accelerated plant recovery, as well as operating costs, including nuclear fuel and nuclear fuel financing costs, and incremental capital expenditures, were subject to balancing account treatment through December 31, 2001. The San Onofre and Palo Verde rate recovery plans and the Palo Verde balancing account were part of the transition cost balancing account (TCBA). See further discussion of the TCBA in "Regulatory Assets and Liabilities."

The nuclear rate-making plans and the TCBA mechanism were to continue for rate-making purposes at least 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 of December 31, 2000, SCE was no longer able to conclude that the unamortized nuclear investment was probable of recovery through the rate-making process. As a result, this balance was written off as a charge to earnings at that time. As a result of the CPUC's April 4, 2002 decision that returned SCE's URG assets to cost-based ratemaking, SCE reestablished for financial reporting purposes its unamortized nuclear investment and related flow-through taxes, retroactive to August 31, 2001, based on a 10-year recovery period, effective January 1, 2001, with a corresponding credit to earnings. SCE adjusted the procurement-related obligations account (PROACT) regulatory asset balance to reflect recovery of the nuclear investment in accordance with the final URG decision.

In a September 2001 decision, the CPUC granted SCE's request to continue the current rate-making treatment for Palo Verde, including the continuation of the existing nuclear unit incentive procedure with a 5¢ per kWh cap on replacement power costs, until resolution of SCE's next general rate case or further CPUC action. Palo Verde's existing nuclear unit incentive procedure calculates a reward for performance of any unit above an 80% capacity factor for a fuel cycle. The San Onofre Units 2 and 3 incentive rate-making plan will continue until December 31, 2003. In its general rate case, SCE has requested to transition San Onofre Units 2 and 3 back to traditional cost-of-service ratemaking on January 1, 2004, and to return Palo Verde to traditional cost-of-service ratemaking upon the effective date of the decision on that application.

Other Nonoperating Income and Deductions

Other nonoperating income and deductions are as follows:

In millions Year ended December 31,	2002	2001	2000
Nonutility nonoperating income	$ 11	$ 51	$ 44
Utility nonoperating income	82	57	118
Total nonoperating income	$ 93	$ 108	$ 162
Nonutility nonoperating deductions	$ 79	$ 32	$ 12
Utility nonoperating deductions	(2)	38	110
Total nonoperating deductions	$ 77	$ 70	$ 122

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 changed its accounting method for major maintenance to record such expenses as incurred consistent with guidance provided by the Securities and Exchange Commission. The cumulative effect of the change in accounting method was a $22 million (after-tax) increase to income from continuing operations in 2000.

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 2002, $7 million in 2001 and $11 million in 2000. AFUDC – debt was $8 million in 2002, $9 million in 2001 and $10 million in 2000.

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 4.2% for 2002, and 3.6% for 2001 and 2000.

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

Generation plant	30 years to 45 years
Distribution plant	24 years to 53 years
Transmission plant	40 years to 60 years
Other plant	5 years to 40 years

SCE's net investment in generation-related utility plant was $842 million at December 31, 2002 and $1.0 billion at December 31, 2001.

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

Nonutility property, including leasehold improvements, 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 and over the lease term for leasehold improvements.

Depreciation expense stated as a percent of average original cost of depreciable nonutility property was, on a composite basis, 3.5% for 2002, 4.2% for 2001 and 2.9% for 2000.

Emission allowances were acquired by EME as part of its Illinois plants and Homer City facilities acquisitions. Although the emission allowances granted under this program are freely transferable, EME intends to use substantially all the emission allowances in the normal course of its business to generate electricity. Accordingly, Edison International has classified emission allowances expected to be used by EME to generate power as part of nonutility property. These acquired emission allowances will be amortized over the estimated lives of the plants on a straight-line basis.

Estimated useful lives for nonutility property are as follows:

Furniture and equipment	3 years to 11 years
Building, plant and equipment	3 years to 100 years
Emission allowances	25 years to 40 years
Civil works	40 years to 100 years
Leasehold improvements	Life of lease

Purchased Power

SCE purchased power through the California Power Exchange (PX) and California Independent System Operator (ISO) from April 1998 through mid-January 2001. SCE has bilateral forward contracts with other entities and power-purchase contracts with other utilities and independent power producers classified as qualifying facilities (QFs). Purchased power detail is provided below:

In millions Year ended December 31,	**2002**	2001	2000
PX/ISO:			
Purchases	**$ 75**	$ 775	$ 8,449
Generation sales	—	324	6,120
Purchased power – PX/ISO – net	**75**	451	2,329
Purchased power – bilateral contracts	**61**	188	—
Purchased power – interutility/QF contracts	**1,880**	3,131	2,358
Total	**$ 2,016**	$ 3,770	$ 4,687

Net PX/ISO amounts for 2002 reflect only billing adjustments. These billing adjustments are recovered through the PROACT and have no impact on earnings.

From January 17, 2001 to December 31, 2002, the California Department of Water Resources (CDWR) purchased power for delivery to SCE's customers in an amount equal to the difference between customer requirements and supplies provided through QF and bilateral contracts, and SCE's utility retained generation. Effective January 1, 2003, SCE assumed responsibility for power requirements not met by the CDWR. Power purchased by the CDWR for delivery to SCE's customers is not considered a cost to SCE.

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.

The TCBA was established for the recovery of generation-related transition costs during the four-year rate freeze period. The transition revenue account (TRA) was a CPUC-authorized regulatory asset account in which SCE recorded the difference between revenue received from customers through frozen rates and the costs of providing service to customers, including power procurement costs.

The gains resulting from the sale of 12 of SCE's generating plants during 1998 were credited to the TCBA. 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.

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 account overcollections (which amounted to $1.5 billion as of December 31, 2000) to be transferred monthly to the TRA, rather than annually to the TCBA (as previously required). 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.

There are many factors that affect SCE's ability to recover its regulatory assets. SCE assessed the probability of recovery of its generation-related regulatory assets in light of the CPUC's March 27, 2001, decisions, including the retroactive transfer of balances from SCE's TRA to the 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. SCE was unable to conclude that its generation-related regulatory assets were probable of recovery through the rate-making process as of December 31, 2000. Therefore, in accordance with accounting rules, SCE recorded a $2.5 billion after-tax charge to earnings at that time, to write off the TCBA and other regulatory assets.

In addition to the TCBA, generation-related regulatory assets totaling $1.3 billion (including the 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.

In accordance with an October 2001 settlement agreement between the CPUC and SCE, the CPUC passed a resolution on January 23, 2002 allowing SCE to establish the PROACT regulatory asset for previously incurred energy procurement costs, retroactive to August 31, 2001. The settlement agreement called for the end of the TCBA mechanism as of August 31, 2001, and continuation of the rate freeze (including surcharges) until the earlier of December 31, 2003 or the date SCE recovers its previously incurred (undercollected) power procurement costs. During a period beginning on September 1, 2001 and ending on the earlier of the date that SCE has recovered all of its procurement-related obligations recorded in the PROACT or December 31, 2005, SCE applies to the PROACT the difference between SCE's revenue from retail electric rates (including surcharges) and the costs that SCE is authorized by the CPUC to recover in retail electric rates. The balance in the PROACT accrues interest. If SCE has not recovered the entire balance by December 31, 2003, the unrecovered balance will be amortized for up to an additional two years.

Based on the CPUC's April 2002 decision related to SCE's utility-retained generation, during the second quarter of 2002, SCE reestablished for financial reporting purposes regulatory assets related to its unamortized nuclear facilities, purchased-power settlements and flow-through taxes.

Due to the current status of the Mohave Generating Station (Mohave) Proceeding (discussed in Note 2), SCE has concluded that it is probable Mohave will be shut down at the end of 2005 and that its book value must be reduced to fair value in accordance with an impairment-related accounting standard. Based on SCE's expectation that any unrecovered book value at the end of 2005 would be recovered in future rates through the rate-making mechanism discussed in its May 17, 2002 application and again in its January 30, 2003 supplemental testimony, and in accordance with accounting standards for rate-regulated enterprises, SCE reclassified for financial reporting purposes approximately $61 million of Mohave's $88 million book value (at December 31, 2002) to a regulatory asset as of December 31, 2002.

Regulatory assets, less regulatory liabilities, included in the consolidated balance sheets are:

In millions December 31,	2002	2001
PROACT – net	$ 574	$ 2,641
Rate reduction notes – transition cost deferral	1,215	1,453
Unamortized nuclear investment – net	630	—
Unamortized coal plant investment – net	61	—
Other:		
Flow-through taxes – net	1,336	1,017
Unamortized loss on reacquired debt	237	254
Environmental remediation	70	57
Regulatory balancing accounts and other – net	224	189
Total	**$ 4,347**	$ 5,611

The regulatory asset related to the rate reduction notes will be recovered over the terms of those notes. The net regulatory asset related to the unamortized nuclear investment will be recovered by the end of the remaining useful lives of the nuclear assets. SCE has requested a four-year recovery period for the net regulatory asset related to its unamortized coal plant investment. CPUC approval is pending. The other regulatory assets and liabilities are being recovered through other components of electric rates.

Balancing account undercollections and overcollections accrue interest based on a three-month commercial paper rate published by the Federal Reserve. PROACT accrues interest based on the interest expense for the debt issued to finance the procurement-related obligations, net of interest income on SCE's cash balance. Income tax effects on all balancing account changes are deferred.

Related Party Transactions

Certain EME subsidiaries have 49% – 50% ownership in partnerships (QFs) that sell electricity generated by their project facilities to SCE under long-term power purchase agreements with terms and pricing approved by the CPUC. SCE's purchases from these partnerships were $548 million in 2002, $983 million in 2001 and $716 million in 2000.

Restricted Cash

Edison International had total restricted cash of $459 million at December 31, 2002 and $620 million at December 31, 2001. Of the total restricted cash, $47 million and $35 million, respectively, was included in the caption "Prepayments and other current assets" at December 31, 2002 and 2001 and $412 million and $585 million, respectively, was included in the caption "Other deferred charges" at December 31, 2002 and 2001. The restricted amounts included in the caption "Prepayments and other current assets" are used exclusively to make scheduled payments on the current maturities of rate reduction notes issued on behalf of SCE by a special purpose entity. The restricted amounts included in the caption "Other deferred charges" are primarily to pay amounts for debt payments at MEHC and EME and letter of credit expenses at EME, as well as to serve as collateral at Edison Capital for outstanding letters of credit. The restricted amount at December 31, 2001 also included collateral that Edison Capital posted as security for its mark-to-market exposure on an interest rate swap.

Revenue

Electric utility revenue is recognized as electricity is delivered and includes amounts for services rendered but unbilled at the end of each year. Amounts charged for services rendered are based on CPUC-authorized rates. Rates include amounts for current period costs, plus the recovery of previously incurred costs (see discussions under "Regulatory Assets and Liabilities"). However, in accordance with accounting standards for rate-regulated enterprises, amounts currently authorized in rates for recovery of costs to be incurred in the future are not considered as revenue until the associated costs are incurred.

Since January 17, 2001, power purchased by the CDWR or through the ISO for SCE's customers is not considered a cost to SCE because SCE is acting as an agent for these transactions. Further, amounts billed to ($1.4 billion in 2002 and $2.0 billion in 2001) and collected from its customers for these power purchases and CDWR bond-related costs (effective November 15, 2002 for bond-related costs) are being remitted to the CDWR and are not recognized as revenue to SCE.

Generally, nonutility power generation revenue is recorded as electricity is generated or services are provided. Some nonutility power generation revenue from power sales contracts is deferred and amortized to income over the life of the contracts. Nonutility power generation revenue is adjusted for price differentials resulting from electricity rate swap agreements in the United States, United Kingdom and Australia.

Generally, financial services and other revenue is recorded by recognizing income from leveraged leases over the term of the lease so as to produce a constant rate of return based on the investment leased. Ordinary gains and losses from sale of assets are recognized at the time of the transaction.

Stock-Based Employee Compensation

Edison International has three stock-based employee compensation plans, which are described more fully in Note 7. Edison International accounts for those plans using the intrinsic value method. Upon grant, no stock-based employee compensation cost is reflected in net income, as all options granted under those plans had an exercise price equal to the market value of the underlying common stock on the date of grant. Compensation expense recorded under the stock-compensation program was $13 million in 2002, $1 million in 2001 and $5 million in 2000. The following table illustrates the effect on net income and earnings per share if Edison International had used the fair-value accounting method.

In millions Year ended December 31,	**2002**	2001	2000
Net income (loss), as reported	**$ 1,077**	$ 1,035	$ (1,943)
Less: Additional stock-based compensation expense using the fair-value accounting method – net of tax	**(3)**	4	11
Pro forma net income (loss)	**$ 1,080**	$ 1,031	$ (1,954)
Basic earning (loss) per share:			
As reported	**$ 3.31**	$ 3.18	$ (5.84)
Pro forma	**$ 3.31**	$ 3.17	$ (5.87)
Diluted earnings (loss) per share:			
As reported	**$ 3.28**	$ 3.17	$ (5.84)
Pro forma	**$ 3.29**	$ 3.16	$ (5.87)

Supplemental Accumulated Other Comprehensive Income (Loss) Information

Supplemental information regarding Edison International's accumulated other comprehensive income (loss), including the discontinued operations of the Ferrybridge and Fiddler's Ferry power plants and Lakeland project, is:

In millions December 31,	**2002**	2001
Foreign currency translation adjustments – net	**$ (8)**	$ (133)
Minimum pension liability – net[(1)]	**(21)**	—
Unrealized loss on investments – net	**(9)**	—
Cumulative effect of change in accounting for derivatives	**154**	148
Unrealized losses on cash flow hedges – net	**(379)**	(359)
Reclassification adjustment for gain (loss) included in net income	**16**	16
Accumulated other comprehensive loss	**$ (247)**	$ (328)

(1) The minimum pension liability is discussed in Note 7, Employee Compensation and Benefit Plans.

Unrealized gains (losses) on cash flow hedges included those related to EME's hedge agreement with the State Electricity Commission of Victoria for electricity prices from the Loy Yang B project in Australia.

This contract does not qualify under the normal sales and purchases exception because financial settlement of the contract occurs without physical delivery. Included in Edison International's accumulated other comprehensive loss at December 31, 2002, was $77 million related to EME's unrealized losses on cash flow hedges resulting from this contract. These losses arise because current forecasts of future electricity prices in these markets are greater than contract prices. In addition to this contract, unrealized gains (losses) on cash flow hedges included those related to EME's share of interest rate swaps of its unconsolidated affiliates and the Loy Yang B project. Interest rate swaps entered into to hedge the floating interest rate risk on MEHC's $385 million term loan due 2006 qualify for treatment under the derivative accounting standard as cash flow hedges with appropriate adjustments made to other comprehensive income.

Unrealized gains (losses) on cash flow hedges also included those related to SCE's interest rate swap. The swap terminated on January 5, 2001, but the related debt matures in 2008. The unamortized loss of $11 million (as of December 31, 2002, net of tax) on the interest rate swap will be amortized over a period ending in 2008. Approximately $2 million, after tax, of the unamortized loss on this swap will be reclassified into earnings during 2003.

As EME's hedged positions are realized, approximately $6 million, after tax, of the net unrealized gains on cash flow hedges at December 31, 2002 are expected to be reclassified into earnings during 2003. EME expects that when the hedged items are recognized in earnings, the net unrealized gains associated with them will be offset. The maximum period over which EME has designated a cash flow hedge, excluding those forecasted transactions related to the payment of variable interest on existing financial instruments, is 14 years. Actual amounts ultimately reclassified into earnings over the next 12 months could vary materially from this estimated amount as a result of changes in market conditions.

Supplemental Cash Flows Information

Edison International supplemental cash flows information is:

In millions Year ended December 31,	**2002**	2001	2000
Cash payments for interest and taxes:			
Interest – net of amounts capitalized	**$ 1,113**	$1,192	$1,128
Tax payments (receipts)	**(301)**	(70)	3
Non-cash investing and financing activities:			
Obligation to fund investments in partnerships and unconsolidated subsidiaries	**—**	$ 4	$ 42
Details of assets acquired:			
Fair value of assets acquired	**$ 16**	$ 898	$ 523
Cash paid for acquisitions	**(16)**	(97)	(126)
Liabilities assumed	**$ —**	$ 801	$ 397
Details of senior secured credit facility transaction:			
Retirement of credit facility	**$ 1,650**	—	—
Cash paid on retirement of credit facility	**(50)**	—	—
Senior secured credit facility replacement	**$ 1,600**	—	—

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 accumulated other comprehensive income in shareholders' equity. Gains or losses resulting from foreign currency transactions are included in other nonoperating income or deductions. Foreign currency transaction gains/(losses) were $(8) million, $2 million and $13 million for 2002, 2001 and 2000, respectively.

Note 2. Regulatory Matters

CPUC Litigation Settlement Agreement

In 2001, SCE and the CPUC entered into a settlement of SCE's lawsuit against the CPUC, which sought a ruling that SCE is entitled to full recovery of its past electricity procurement costs. A key element of the settlement agreement was the establishment of a $3.6 billion rate-recovery mechanism called the PROACT as of August 31, 2001. The Utility Reform Network (TURN), a consumer advocacy group, and other parties appealed to the federal court of appeals seeking to overturn the stipulated judgment of the district court that approved the settlement agreement. On March 4, 2002, the court of appeals heard argument on the appeal, and on September 23, 2002 the court issued its opinion. In the opinion, the court affirmed the district court on all claims, with the exception of the challenges founded upon California state law, which the appeals court referred to the California Supreme Court. Specifically, the appeals court affirmed the district court in the following respects: (1) the district court did not err in denying the motions to intervene brought by entities other than TURN; (2) the district court did not err in denying standing for the entities other than TURN to appeal the stipulated judgment; (3) the district court was not deprived of original jurisdiction over the lawsuit; (4) the district court did not err in declining to abstain from the case; (5) the district court did not exceed its authority by approving the stipulated judgment without TURN's consent; (6) the district court's approval of the settlement agreement did not deny TURN due process; and (7) the district court did not violate the Tenth Amendment of the United States Constitution in approving the stipulated judgment. In sum, the appeals court concluded that none of the substantive arguments based on federal statutory or constitutional law compelled reversal of the district court's approval of the stipulated judgment.

However, the appeals court stated in its opinion that there is a serious question whether the settlement agreement violated state law, both in substance and in the procedure by which the CPUC agreed to it. The appeals court added that if the settlement agreement violated state law, the CPUC lacked capacity to consent to the stipulated judgment, and the stipulated judgment would need to be vacated. The appeals court indicated that, on a substantive level, the stipulated judgment appears to violate California's electric industry restructuring statute providing for a rate freeze. The appeals court also indicated that, on a procedural level, the stipulated judgment appears to violate California laws requiring open meetings and public hearings. Because federal courts are bound by the pronouncements of the state's highest court on applicable state law, and because the federal appeals court found no controlling precedents from California courts on the issues of state law in this case, the appeals court issued a separate order certifying those issues in question form to the California Supreme Court and requested that the California Supreme Court accept certification.

The California Supreme Court accepted the certification, reformulated one of the certified questions as SCE had requested, and set a briefing schedule that will be followed by oral argument. SCE and the CPUC filed their respective opening briefs on the certified questions on December 20, 2002. TURN filed its answering brief on January 24, 2003 and SCE and the CPUC filed reply briefs on February 13, 2003. Various third parties, including the Governor, submitted friend-of-the-court briefs concerning the certified questions. In addition, the California Supreme Court requested that the parties provide supplemental briefing with respect to an issue related to California's open meeting laws. The parties have complied with such request. The California Supreme Court will set a hearing date on the matter. Once the California Supreme Court rules, the matter will return to the Ninth Circuit, which in turn should be guided by the California Supreme Court's answers and interpretations of state law. In the meantime, the case is stayed in the federal appellate court. SCE continues to operate under the settlement agreement. SCE continues to believe it is probable that SCE ultimately will recover its past procurement costs through regulatory mechanisms, including the PROACT. However, SCE cannot predict with certainty the outcome of the pending legal proceedings.

Under the settlement agreement, SCE cannot pay dividends or other distributions on its common stock (all of which is held by its parent, Edison International) prior to the earlier of the date on which SCE has recovered all of its procurement-related obligations or January 1, 2005, except that if SCE has not recovered all of its procurement-related obligations by December 31, 2003, SCE may apply to the CPUC for consent to resume common stock dividends prior to January 1, 2005 and the CPUC will not unreasonably withhold its consent.

CDWR Power Purchases and Revenue Requirement Proceedings

In accordance with an emergency order signed by the governor, the CDWR began making emergency power purchases for SCE's customers on January 17, 2001. Amounts SCE bills to and collects from its customers for electric power purchased and sold by the CDWR are remitted directly to the CDWR and are not recognized as revenue by SCE. In February 2001, Assembly Bill 1 (First Extraordinary Session, AB 1X) was enacted into law. AB 1X authorized the CDWR to enter into contracts to purchase electric power and sell power at cost directly to SCE's retail customers and authorized the CDWR to issue bonds to finance electricity purchases. In addition, the CPUC has the responsibility to allocate the CDWR's revenue requirement among the customers of SCE, Pacific Gas and Electric (PG&E) and San Diego Gas & Electric (SDG&E).

On February 21, 2002, the CPUC allocated to SCE's customers $3.5 billion (38.2%) of the CDWR's total power procurement revenue requirement of $9 billion for 2001 and 2002. This resulted in an average annual CDWR revenue requirement of $1.7 billion being allocated to SCE. In its February 21, 2002 decision, the CPUC ordered that allocation of that revenue requirement to each utility be trued-up based on the CDWR's actual recorded costs for the 2001–2002 period and a specific methodology set forth in that decision.

On October 24, 2002, the CPUC issued a decision which adopts a methodology for establishing a charge to repay bond-related costs resulting from the CDWR's $11 billion bond issue. The bond charge is to be set by dividing the annual revenue requirement for bond-related costs by an estimate of the annual electricity consumption of bundled service customers subject to the charge. The charge will apply to electricity consumed on and after November 15, 2002 and will be set annually based on annual expected debt-related costs and projected electricity consumption. For 2003, the CPUC allocated to SCE's customers $331 million (about 44%) of the CDWR's bond charge revenue requirement of $745 million. The bond charge is set at a rate of 0.513¢ per kWh for SCE's customers. In a November 7, 2002 decision, the CPUC assigned responsibility for a portion of the bond charge to direct access customers.

On December 17, 2002, the CPUC adopted an allocation of the CDWR's forecast power procurement revenue requirement for 2003, based on the quantity of electricity expected to be supplied under the CDWR contracts to customers of each of the three utility companies by the CDWR. SCE's allocated share is $1.9 billion of the CDWR's total 2003 power procurement revenue requirement of $4.5 billion. This is an interim allocation and will be superseded by a later allocation after the CDWR submits a supplemental determination of its 2003 revenue requirement. The CPUC stated that the later allocation could result in a reduction in the CDWR's revenue requirement, with a corresponding decrease in the CDWR's rate charged to bundled service customers. The CPUC's December 17, 2002 decision did not address issues relating to the true-up of the CDWR's 2001–2002 revenue requirement, stating that those issues will be addressed after actual data for 2002 becomes available, expected in April 2003.

Electric Line Maintenance Practices Proceeding

In August 2001, the CPUC issued an Order Instituting Investigation (OII) regarding SCE's overhead and underground electric line maintenance practices. The OII is based on a report issued by the CPUC's Protection and Safety Consumer Services Division (CPSD), which alleges SCE had a pattern of noncompliance with the CPUC's General Orders for the maintenance of electric lines over the period 1998–2000. The OII also alleges that noncompliant conditions were involved in 37 accidents resulting in death, serious injury or property damage. The CPSD identified 4,817 alleged "violations" of the General Orders during the three-year period. The OII placed SCE on notice that it is potentially subject to a penalty of between $500 and $20,000 for each violation or accident.

Prepared testimony was filed on this matter in April 2002, and hearings were concluded in September 2002. In opening briefs filed on October 21, 2002, the CPSD recommended that SCE be assessed a penalty of $97 million, while SCE requested that the CPUC dismiss the proceeding and impose no penalties. SCE stated in its opening brief that it has acted reasonably, allocating its financial and human resources in pursuit of the optimum combination of employee and public safety, system reliability, cost-effectiveness, and technological advances. SCE also encouraged the CPUC to transfer consideration of issues related to development of standardized inspection methodologies and inspector training to an Order Instituting Rulemaking to revise these General Orders opened by the CPUC in October 2001, or to a new rulemaking proceeding. On March 14, 2003, SCE and the CPSD filed opening briefs in response to the assigned administrative law judge's direction to address application of the appropriate standard to govern SCE's electric line maintenance obligation. Oral arguments are scheduled for April 22, 2003. A decision is expected in the second or third quarter of 2003. SCE is unable to predict with certainty whether this matter ultimately will result in any material financial penalties or impacts on SCE.

Generation Procurement Proceedings

In October 2001, the CPUC issued an Order Instituting Rulemaking directing SCE and the other major California electric utilities to provide recommendations for establishing policies and mechanisms to enable the utilities to resume power procurement by January 1, 2003. Although the proceeding began before the enactment of Assembly Bill 57 (AB 57), that statute (in its draft form, and, after enactment, in its final form) has guided the proceeding. Senate Bill 1078 (SB 1078) has also had an impact on this proceeding, as described below.

AB 57, which provides for SCE and the other California utilities to resume procuring power for their customers, was signed into law by the Governor of California in September 2002. A second senate bill was enacted not long after AB 57 to shorten the time period between the adoption of a utility's initial procurement plan and the resumption of procurement from 90 to 60 days. Under these statutes, SCE is effectively allowed to recover procurement costs incurred in compliance with an approved procurement plan. Only limited categories of costs, including contract administration and least-cost dispatch, are subject to reasonableness reviews.

In addition, SB 1078, which was signed into law by the Governor in September 2002 and is effective January 1, 2003, provides that, commencing January 1, 2003, SCE and other California utilities shall increase their procurement of renewable resources by at least an additional 1% of their annual electricity sales per year so that 20% of the utility's annual electricity sales are procured from renewable resources by no later than December 31, 2017. Utilities are not required to enter into long-term contracts for renewable resources in excess of a market-price benchmark to be established by the CPUC pursuant to criteria set forth in the statute. Similar provisions are also found in AB 57.

The CPUC issued four major decisions in this proceeding in 2002 addressing: (1) transitional procurement contracts; (2) the allocation of contracts previously entered into by the CDWR among the three major California utilities; (3) the resumption of power procurement activities by these utilities on January 1, 2003, and adoption of a regulatory framework for such activities; and (4) SCE's short-term procurement plan for 2003.

The first decision, relating to transitional procurement contracts, was issued on August 22, 2002. It authorized the utilities to enter into capacity contracts between the effective date of the decision and January 1, 2003, referred to as the transitional procurement period. Under this decision, the CPUC would approve or disapprove the transitional contracts proposed by a utility by means of an expedited advice letter process. As a result of this process, SCE entered into six transitional capacity contracts with terms up to five years. These contracts were approved by the CPUC.

This decision also required the utilities to procure, during the transitional procurement period, at least 1% of their annual electricity sales through a competitive procurement process set aside for renewable resources. The utilities were required to solicit bids for renewable contracts with terms of five, ten and fifteen years and to enter into contracts providing for the commencement of deliveries by the end of 2003. In accordance with this CPUC directive, SCE conducted a solicitation of offers from owners of renewable resources and, based upon the results of the solicitation, provisionally entered into six contracts, subject to subsequent CPUC approval. On December 24, 2002 and January 14, 2003, SCE filed advice letters seeking CPUC approval of these six renewable contracts. On January 30, 2003, the CPUC issued a resolution approving four of the six renewable contracts. In addition, draft resolutions have been issued disapproving the two remaining renewable contracts, with an alternative draft resolution approving one of the two remaining contracts. The CPUC is expected to rule on the remaining contracts in the second quarter of 2003.

The second decision addressed the issue of allocating among the three major California utilities the contracts previously entered into by the CDWR. In this decision, issued on September 19, 2002, the

CPUC allocated the CDWR contracts on a contract-by-contract basis. Under the decision, utility responsibility for the contracts is limited to that of scheduling and dispatch. The decision significantly reduces SCE's net short and also increases the likelihood that SCE will have excess power during certain periods. Wholesale revenue from the sale of such surplus energy is to be prorated between the CDWR and SCE, pursuant to several CPUC orders. Under the decision, SCE acts as limited agent for the CDWR for contract implementation, but legal title, financial reporting and responsibility for the payment of contract-related bills remain with the CDWR. On January 17, 2003, the CDWR filed a petition to modify the September 19, 2002 decision requesting the allocation of four additional contracts which are not currently part of the CDWR's 2003 revenue requirement. The CPUC allocated one of the four contracts to SCE in a February 27, 2003 decision.

The third decision was issued on October 24, 2002. It ordered the utilities to resume procurement and adopting the regulatory framework for the utilities resuming full procurement responsibilities on January 1, 2003. The decision distinguished the utilities' responsibilities on the basis of short-term (2003) versus long-term (2004–2024) procurement. It adopted the utilities' procurement plans filed on May 1, 2002, and directed that they be modified prior to January 1, 2003, to reflect the decision, the allocation of existing CDWR contracts, and any transitional procurement done under the August 22, 2002 decision. The October 24, 2002 decision also set forth a detailed process and procedural schedule to develop long-term procurement planning that includes the filing by each utility of a long-term plan by April 1, 2003, and an evidentiary hearing in early July 2003. In addition, the decision called for each of the utilities to establish a balancing account, to be known as the energy resource recovery account, to track energy costs. These balancing accounts will be used for examining procurement rate adjustments on a semi-annual basis, as well as on a more expedited basis in the event fuel and purchased-power costs exceed a prescribed threshold. The decision also provided clarification as to certain elements of the CPUC's August 22, 2002 order regarding interim procurement of additional renewable resources and established a schedule for parties to provide comments in January 2003 on various aspects of SB 1078 implementation in anticipation of an implementation report to be submitted by the CPUC to the legislature by June 30, 2003. On November 25, 2002 SCE filed an application with the CPUC for rehearing of the October 24 decision seeking the correction of legal errors in the decision. The CPUC has not yet ruled on SCE's application for rehearing, but has indicated that it will address SCE's application and others in future decisions.

The fourth decision, issued on December 19, 2002, approved modified short-term procurement plans filed in November 2002 by SCE, PG&E, and SDG&E. It modified and clarified the cost-recovery mechanisms and standards of behavior adopted in the October 24 decision, and provided further guidance on the long-term planning process to be undertaken in the next phase of the power procurement proceeding. The CPUC found that the utilities were capable of resuming full procurement on January 1, 2003 and ordered that they take all necessary steps to do so.

Among other things, the December 19, 2002 decision determined that SCE's maximum disallowance risk exposure for procurement activities, contract administration and least-cost dispatch, would be capped at twice SCE's annual procurement administrative expenses.

On January 21, 2003, SCE filed an application for rehearing of the December 19 procurement plan decision. Issues addressed included certain standard of conduct provisions, bilateral contracting, level of customer risk tolerance, lack of an appropriate tracking mechanism for certain costs, lack of definition for least cost dispatch, and the finding that SCE was non-compliant with the August 22, 2002 decision. SCE has filed a petition for modification which addressed, among other things, the need for the cap on SCE's maximum disallowance risk exposure to be extended to cover all procurement activities.

On March 4, 2003, SCE also filed a motion for consolidated consideration of the numerous applications for rehearing and petitions for modification that have been filed, and will be filed, on the various CPUC decisions addressing the investor owned utilities management of their power supply portfolios. In the motion, SCE urged the CPUC to conduct a comprehensive review of its procurement decisions and act on the various applications for rehearing and petitions for modification in an integrated manner, avoiding the piecemeal action that failed to fully resolve the outstanding issues.

In accordance with the CPUC's October 24, 2002 decision, on February 3, 2003, SCE and the other utilities filed outlines of their long-term procurement plans. SCE proposed in its outline that the CPUC separate the proceeding so that SCE would file a separate 2004 short-term procurement plan as well as its long-term plan. The assigned administrative law judge agreed with this proposal. SCE plans to file the long-term resource plan and the 2004 short-term procurement plan on April 1, 2003 and May 1, 2003, respectively. Hearings on the short-term plan and certain key issues in the long-term plan are expected to take place in June and July 2003. The issues that will be incorporated into the long-term plan were addressed during the prehearing conference on March 7, 2003. Pursuant to a ruling of the assigned administration law judge, issues related to implementation of SB 1078 will be determined on a separate, expedited schedule. Testimony on the implementation of SB 1078 will be filed on March 27, 2003 and hearings will be held in April 2003. A preliminary decision is expected in June 2003 followed by a report by the CPUC to the legislature on June 30, 2003.

Holding Company Proceeding

In April 2001, the CPUC issued an order instituting investigation that reopens the past CPUC decisions authorizing utilities to form holding companies and initiates an investigation into, among other things: whether the holding companies violated CPUC requirements to give first priority to the capital needs of their respective utility subsidiaries; 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. On January 9, 2002, the CPUC issued an interim decision on the first priority condition. The decision stated that, at least under certain circumstances, the condition includes the requirement that holding companies infuse all types of capital into their respective utility subsidiaries when necessary to fulfill the utility's obligation to serve. The decision did not determine if any of the utility holding companies had violated this condition, reserving such a determination for a later phase of the proceedings. On February 11, 2002, SCE and Edison International filed an application before the CPUC for rehearing of the decision. On July 17, 2002, the CPUC affirmed its earlier decision on the first priority condition and also denied Edison International's request for a rehearing of the CPUC's determination that it had jurisdiction over Edison International in this proceeding. On August 21, 2002, Edison International and SCE jointly filed a petition requesting a review of the CPUC's decisions with regard to first priority considerations, and Edison International filed a petition for a review of the CPUC decision asserting jurisdiction over holding companies, both in state court as required. PG&E and SDG&E and their respective holding companies filed similar challenges, and all cases have been transferred to the First District Court of Appeals in San Francisco. The CPUC filed briefs in opposition to the writ petitions. Edison International, SCE and the other petitioners filed reply briefs on March 6, 2003. No hearings have been scheduled. The court may rule without holding hearings. Edison International cannot predict with certainty what effects this investigation or any subsequent actions by the CPUC may have on Edison International or any of its subsidiaries.

Mohave Generating Station Proceeding

On May 17, 2002, SCE filed with the CPUC an application to address certain issues facing the future extended operation of Mohave which is partly owned by SCE. Mohave obtains all of its coal supply from the Black Mesa Mine in northeast Arizona, located on lands of the Navajo Nation and Hopi Tribe (the Tribes). This coal is delivered from the mine to Mohave by means of a coal slurry pipeline, which requires water that is obtained from groundwater wells located on lands of the Tribes in the mine vicinity.

Due to the lack of progress in negotiations with the Tribes and other parties to resolve several coal and water supply issues, SCE's application stated that it probably would not be possible for SCE to extend Mohave's operation beyond 2005. Uncertainty over a post-2005 coal and water supply has also prevented SCE and the other Mohave co-owners from starting to make approximately $1.1 billion (SCE's share is $605 million) of Mohave-related investments that will be necessary if Mohave operations are to extend past 2005, including the installation of pollution-control equipment that must be put in place pursuant to a 1999 Consent Decree related to air quality, if Mohave's operations are extended past 2005.

SCE's May 17, 2002 application requested either: a) pre-approval for SCE to immediately begin spending up to $58 million on Mohave pollution controls in 2003, if by year-end 2002, SCE had obtained adequate assurance that the outstanding coal and slurry-water issues would be satisfactorily resolved; or b) authority for SCE to establish certain balancing accounts and otherwise begin preparing to terminate Mohave's coal-fired operations at the end of 2005.

The CPUC issued a ruling on January 7, 2003, requesting further written testimony from SCE and initial written testimony from other parties on specified issues relating to Mohave and its coal and slurry-water supply. The ruling states that the purpose of the CPUC proceeding is to determine whether it is in the public interest to extend Mohave operations post 2005. In its supplemental testimony submitted on January 30, 2003, SCE stated, among other things, that the currently available information is not sufficient for the CPUC to make this determination at this time. The testimony states that neither SCE nor any other party has sufficient assurance of whether and how the currently unresolved coal and water supply issues will be resolved. Unless all key unresolved issues are resolved in a timely way, moreover, Mohave will cease operation as a coal-fired plant at the end of 2005 under the terms of the consent decree and the existing coal supply agreements. In that event, there would be no need for the CPUC to make the determination it has described, since extension of the present operating period would not be an option. SCE's supplemental testimony accordingly requests that the CPUC authorize the establishment of the balancing accounts that SCE first requested in its May 17, 2002 application in order to prepare for an orderly shutdown of Mohave by the end of 2005, but the testimony also states that even with such authorization, SCE will continue to work with the relevant stakeholders to attempt to resolve the issues surrounding Mohave's coal and slurry-water supply.

On January 14, 2003, the Natural Resources Defense Council, Black Mesa Trust and others served a notice of intent to sue the U.S. Department of the Interior and other federal government agencies and individuals, challenging the failure of the government to issue a final permit to Peabody Western Coal Company for the operation of the Black Mesa Mine. The prospective plaintiffs claim that the federal government must begin a proceeding for issuance of a final permit to Peabody rather than allow Peabody to continue long-term operation of the Black Mesa Mine on an interim basis including groundwater extraction for use in the coal slurry pipeline.

The notice indicates that the prospective plaintiffs would then challenge any issuance of a permanent mining permit for the Black Mesa Mine unless, at a minimum, an alternate source of slurry water is obtained. If the prospective plaintiffs prevail in any future lawsuit, the coal supply to Mohave could be interrupted.

In light of all of the issues discussed above, SCE has concluded that it is probable Mohave will be shut down at the end of 2005. Because the expected undiscounted cash flows from the plant during the years 2003–2005 were less than the $88 million carrying value of the plant as of December 31, 2002, SCE incurred an impairment charge of $61 million. However, in accordance with accounting standards for rate-regulated enterprises, this incurred cost was deferred and recorded as a regulatory asset, based on SCE's expectation that any unrecovered book value at the end of 2005 would be recovered in future rates through the rate-making mechanism discussed in its May 17, 2002 application and again in its January 30, 2003 supplemental testimony.

URG Decision

On April 4, 2002, the CPUC issued a decision to return URG assets to cost-based ratemaking through the end of 2002. After that time, SCE's URG-related revenue requirement will be determined through the 2003 general rate case proceeding. Key elements of the URG decision are: retention of the San Onofre incentive pricing mechanism through 2003; recovery of incurred costs for all URG components other than San Onofre; establishment of an amortization schedule for SCE's nuclear plants based on their remaining useful lives; and establishment of balancing accounts for utility generation, purchased power and ISO ancillary services.

Based on this decision, during second quarter 2002, SCE reestablished for financial reporting purposes regulatory assets related to its unamortized nuclear plant, purchased-power settlements and flow-through taxes, reduced the PROACT balance, and recorded a corresponding credit to earnings of $480 million after tax. The impact of the URG decision is reflected in the financial statements as a credit (decrease) to the provisions for regulatory clauses of $644 million, partially offset by an increase in deferred income tax expense of $164 million. The reduction in the PROACT balance reflects a change in the amortization schedule of SCE's unamortized nuclear facilities from the schedule required to be used to calculate the surplus revenue contributed to the PROACT, for rate-making purposes, during the last four months of 2001. Implementation of the URG decision, together with the PROACT mechanism, allowed SCE to reestablish substantially all of the regulatory assets previously written off to earnings.

Wholesale Electricity Markets

On April 25, 2001, after months of high power prices, the FERC issued an order providing for energy price controls during ISO Stage 1 or greater power emergencies (7% or less in reserve power). The order establishes an hourly clearing price based on the costs of the least efficient generating unit during the period. Effective June 20, 2001, the FERC expanded the April 25, 2001, order to include non-emergency periods and price mitigation in the 11-state western region through September 30, 2002. On July 17, 2002, the FERC issued an order reviewing the ISO's proposals to redesign the market and implementing a market power mitigation program for the 11-state western region. The FERC declined to extend beyond September 30, 2002 all of the market mitigation measures it had previously adopted. However, effective October 1, 2002, the FERC extended a requirement, first ordered in its June 19, 2001 decision, that all western energy sellers offer for sale all operationally and contractually available energy. It also ordered a cap on bids for real-time energy and ancillary services of $250/MWh to be effective beginning October 1, 2002, and ordered various other market power mitigation measures. Implementation of the $250/MWh bid cap and other market power mitigation measures were delayed until October 31, 2002 by a FERC order issued September 26, 2002. The FERC did not set a specific expiration date for its new market mitigation plan. SCE cannot yet determine whether the new market mitigation plan adopted by the FERC will be sufficient to mitigate market price volatility in the wholesale electricity markets in which SCE will purchase its residual net short electricity requirements (i.e., the amount of energy needed to serve SCE's customers from sources other than its own generating plants, power purchase contracts and CDWR contracts).

On August 2, 2000, SDG&E filed a complaint with the FERC seeking relief from alleged energy overcharges in the PX and ISO market. SCE intervened in the proceeding on August 14, 2000. On August 23, 2000, the FERC issued an order initiating an investigation of the justness and reasonableness of rates charged by sellers in the PX and ISO markets. Those proceedings were consolidated. On July 25, 2001, the FERC issued an order that limits potential refunds from alleged overcharges by energy suppliers to the ISO and PX spot markets during the period from October 2, 2000 through June 20, 2001, and adopted a refund methodology based on daily spot market gas prices. An administrative law judge conducted evidentiary hearings on this matter in March, August and October 2002 and issued and initial decision on December 12, 2002.

On November 20, 2002, in the consolidated proceeding, the FERC issued an order authorizing 100 days of discovery by market participants into market manipulation and abuse during the period January 1, 2000 through June 20, 2001. SCE joined with the California parties (PG&E, the California Attorney General, the Electricity Oversight Board, and the CPUC to submit briefs and evidence demonstrating that sellers and marketers violated tariffs, withheld power, and distorted and manipulated the California electricity markets.

At a FERC meeting on March 26, 2003, the FERC issued orders that initiated procedures for determining additional refunds arising from market manipulation by energy suppliers. Based on public comments at the meeting and the FERC's press releases, it appears that the FERC acknowledges that there was pervasive gaming and market manipulation of the electric and gas markets in California and on the west coast. A new FERC staff report issued on March 26, 2003 also describes many of the techniques and effects of electric and gas market manipulation. The FERC will be modifying the administrative law judge's initial decision of December 12, 2002 to reflect the fact that the gas indices used in the market manipulation formula overstated the cost of gas used to generate electricity.

SCE has not yet completed an evaluation of the FERC actions taken on March 26, 2003 and cannot determine the timing or amount of any potential refunds. Under the settlement agreement with the CPUC, any refunds will be applied to reduce the PROACT balance until the PROACT is fully recovered. After PROACT recovery is complete, 90% of any refunds will be refunded to ratepayers.

Note 3. Derivative Instruments and Hedging Activities

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, emission and transmission rights, 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 2000).

On January 1, 2001, Edison International adopted a new accounting standard for derivative instruments and hedging activities. Edison International has also adopted subsequent interpretations of this standard issued in July 2001, October 2001 and December 2001. The standard requires derivative instruments to be recognized on the balance sheet at fair value unless they meet the definition of a normal purchase or sale. The normal purchases and sales exception requires, among other things, physical delivery in quantities expected to be used or sold over a reasonable period in the normal course of business. Gains or losses from changes in the fair value of a recognized asset or liability or a firm commitment are reflected in earnings for the ineffective portion of the hedge. For a hedge of the cash flows of a forecasted transaction or a foreign currency exposure, the effective portion of the gain or loss is initially recorded as a separate component of shareholders' equity under the caption "accumulated other comprehensive income," and subsequently reclassified into earnings when the forecasted transaction affects earnings. The ineffective portion of the hedge is reflected in earnings immediately. Fair value changes for EME's trading operations are reflected in earnings.

SCE recorded its interest rate swap agreement (terminated January 5, 2001) and its block forward power-purchase contracts at fair value effective January 1, 2001. The unamortized loss of $11 million (as of December 31, 2002, net of tax) on the interest rate swap will be amortized over a period ending in 2008, when the related debt matures. 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 remaining block forward contracts. Before the PX could do so, on February 2, 2001, the state seized the contracts. On September 30, 2001, a federal appeals court ruled that the Governor of California acted illegally when he seized the contracts held by SCE. In conjunction with its settlement agreement with the CPUC, SCE has agreed to release any claim for compensation against the state for these contracts. However, if the PX prevails in its claims against the state, SCE may receive some refunds.

SCE has bilateral forward power contracts, which are considered normal purchases under accounting rules. 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.

In October and November 2001, SCE purchased $209 million of call options that mitigate its exposure to increases in natural gas prices during 2002 and 2003. This amount is being recovered through the PROACT mechanism. Amounts paid to QFs for energy are based on natural gas prices. Any fair value changes for gas call options are offset through a regulatory balancing account; therefore, fair value changes do not affect earnings.

SCE purchases power from certain QFs in which the contract pricing is based on a natural gas index, but the power is not generated with natural gas. A portion of these contracts is not eligible for the normal purchases and sales exception under accounting rules and the fair value is recorded on the balance sheet. Any fair value changes for these QF contracts are offset through a regulatory mechanism; therefore, fair value changes do not affect earnings.

EME's primary market risk exposures arise from fluctuations in electricity and fuel prices, emission and transmission rights, interest rates and foreign currency exchange rates. EME manages these risks in part by using derivative financial instruments in accordance with established policies and procedures.

In 2001, EME recorded a $250,000, after tax, increase to income from continuing operations, a $6 million (after tax) increase to income from discontinued operations and a $230 million (after tax) decrease to other comprehensive income as the cumulative effect of a change in accounting for derivatives. Upon implementation, EME's forward sales contracts from the Homer City facilities qualified as cash flow hedges. EME did not use the normal purchases and sales exception for these forward sales contracts due to net settlement procedures with counterparties. As a result of higher market prices for forward sales from its Homer City facilities, EME recorded a liability of $116 million at January 1, 2001, deferred tax benefits of $54 million and a decrease in other comprehensive income of $62 million. EME's hedge agreement with the State Electricity Commission of Victoria for electricity prices from its Loy Yang B project in Australia qualified as a cash flow hedge. This contract could not qualify under the normal purchases and sales exception because financial settlement of the contract occurs without physical delivery. As a result of higher market prices for forward sales from EME's Loy Yang B plant, EME recorded a liability of $227 million at January 1, 2001, deferred tax benefits of $68 million and a decrease in other comprehensive income of $159 million. The majority of EME's activities related to the fuel contracts for EME's Collins Station in Illinois did not qualify for either the normal purchases and sales exception or as cash flow hedges. EME could not conclude, based on information available at January 1, 2001, that the timing of generation from the Collins Station met the probable requirement for a specific forecasted transaction under the new accounting standard for derivatives and hedging activities. Accordingly, these contracts were recorded at fair value, with subsequent changes in fair value reflected in nonutility power generation revenue in the consolidated income statement. EME has continued to record fuel contracts for its Collins Station at fair value.

New accounting guidance effective July 1, 2001, modified the normal purchases and sales exception to include electricity contracts which include terms that require physical delivery by the seller in quantities that are expected to be sold in the normal course of business. This modification resulted in EME's Homer City forward sales contracts qualifying for the normal sales and purchases exception commencing July 1, 2001. Based on this accounting guidance, on July 1, 2001, EME eliminated the value of the Homer City forward sales contracts from its consolidated balance sheet. The cumulative effect of this change in accounting is reflected as a $16 million, after tax, decrease to other comprehensive income in 2001. Also, for the period between January 1, 2001 and June 30, 2001, EME applied the normal purchases and sales exception for long-term commodity contracts that included both selling and buying electricity by EME's First Hydro plant. However, the criteria applicable to the buyer of power under the new interpretation precluded the contracts from qualifying under the normal purchases and sales exception as of July 1, 2001, because First Hydro is not contractually obligated to maintain sufficient capacity to meet electricity needs of a customer. Accordingly, EME recorded a $15 million, after tax, increase to income from continuing operations as the cumulative effect of change in accounting for derivatives in the consolidated income statement as of July 1, 2001. All subsequent changes in the fair value of these contracts will be reflected in nonutility power generation revenue in the consolidated income statement.

On April 1, 2002, EME implemented a revised interpretation (issued in December 2001) that resulted in EME's forward electricity contracts no longer qualifying for the normal purchases and sales exception since EME has net settlement agreements with its counterparties. Under this exception, EME records revenue on an accrual basis. Subsequent to implementation of this interpretation, EME accounted for these contracts as cash flow hedges. Under a cash flow hedge, EME records the fair value of the forward sales agreements on its balance sheet and records the effective portion of the cash flow hedge as part of other comprehensive income. The ineffective portion of EME's cash flow hedges is recorded directly in its income statement. Upon implementation, EME recorded assets at fair value of $12 million, deferred taxes of $6 million and a $6 million increase to other comprehensive income as the cumulative effect of adoption of this interpretation.

Under the accounting standard for derivatives and hedging activities, the portion of a cash flow hedge that does not offset the change in value of the transaction being hedged, which is commonly referred to as the ineffective portion, is immediately recognized in earnings. EME recorded a net loss of approximately $2 million and $1 million in 2002 and 2001, respectively, representing the amount of cash flow hedges' ineffectiveness, reflected in nonutility power generation revenue in the consolidated income statement.

Under EME's fixed to variable swap agreements, the fixed interest rate payments are at a weighted average rate of 6.91% and 5.97% at December 31, 2002 and 2001, respectively. Variable rate payments under EME's corporate agreements were based on six-month LIBOR capped at 9% at December 31, 2001. Variable rate payments pertaining to its foreign subsidiary agreements are based on an equivalent interest rate benchmark to LIBOR. The weighted average rate applicable to these agreements was 6.18% and 2.80% at December 31, 2002 and 2001, respectively. Under the variable to fixed swap agreements, EME will pay counterparties interest at a weighted average fixed rate of 6.96% and 7.12% at December 31, 2002 and 2001, respectively. Counterparties will pay EME interest at a weighted average variable rate of 5.10% and 4.76% at December 31, 2002 and 2001, respectively. The weighted average variable interest rates are based on LIBOR or equivalent interest rate benchmarks for foreign denominated interest rate swap agreements. Under EME's interest rate options, the weighted average strike interest rate is was 6.90% and 6.76% and December 31, 2002 and 2001, respectively.

In September 2000, EME acquired the trading operations of Citizens Power LLC, expanding EME's operations beyond the traditional marketing of electric power to include trading of electricity and fuels. 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.

MEHC, a wholly owned indirect subsidiary of Edison International, has two interest rate swaps to hedge floating interest rate risk on its term loan. These contracts qualify for treatment as cash flow hedges with appropriate adjustments made to other comprehensive income. During the years ended December 31, 2002 and 2001, MEHC recorded decreases to other comprehensive income of $5 million (after tax) and $1 million (after tax), respectively, resulting from unrealized holding losses on these contracts. Under the variable-to-fixed swap agreements, MEHC will pay counterparties interest at a weighted average fixed rate of 3.04% and 2.76% at December 31, 2002 and 2001, respectively; counterparties will pay interest at a weighted average variable rate based on LIBOR of 1.63% and 1.98% at December 31, 2002 and 2001, respectively.

Edison Capital had interest rate swaps in place during 2002 and 2001 to reduce the potential impact of changes in interest rates. Edison Capital recorded these swaps on its balance sheet at fair market value under an accounting standard adopted by Edison International in January 2001. In 2001, Edison Capital's earnings were reduced by $4 million, reflecting the fair value change of an interest rate swap that does not qualify for hedge accounting. This swap was terminated in February 2002. In 2002, Edison Capital made payments on its swap agreements at a weighted average rate of 6.08%. No payments were received in 2002. In 2001, Edison Capital made payments on its swap agreements at a weighted average rate of 5.99% and received payments at a weighted average rate of 4.35%. Edison Capital had no swap agreements outstanding as of December 31, 2002.

Fair values of financial instruments are:

In millions December 31,	**2002**	2001
Derivatives:		
Interest rate swap/cap agreements	**$ (56)**	$ (40)
Interest rate options	**(2)**	(1)
Commodity price:		
Electricity	**(100)**	(74)
Natural gas	**77**	83
Foreign currency forward exchange agreements	**—**	(1)
Cross currency interest rate swaps	**(2)**	28
Other:		
Decommissioning trusts	**2,210**	2,275
Long-term receivables	**6**	265
DOE decommissioning and decontamination fees	**(22)**	(25)
QF power contracts	**(70)**	—
Long-term debt	**(9,952)**	(12,686)
Long-term debt due within one year	**(2,812)**	(1,505)
Utility preferred stock subject to mandatory redemption	**(129)**	(118)
Utility preferred stock to be redeemed within one year	**(8)**	(102)
Other preferred securities subject to mandatory redemption	**(246)**	(258)
Short-term debt	**(78)**	(2,421)
Trading Activities:		
Assets	**109**	9
Liabilities	**(17)**	(7)

The fair value of the interest rate hedges is based on quoted market prices.

The fair value of the commodity contracts considers quoted market prices, time value, volatility of the underlying commodities and other factors. The fair value of the electricity rate swap agreements (included under commodity price) is estimated by discounting the future cash flows on the difference between the average aggregate contract price per MW and a forecasted market price per MW, multiplied by the amount of MW sales remaining under contract. The fair value of the QF power contracts is based on financial models; the fair value of the gas call options is based on quoted market prices.

Foreign currency forward exchange agreements and cross currency interest rate swaps are based on bank quotes.

Other fair values are based on: quoted market prices for decommissioning trusts and long-term receivables; discounted future cash flows for U.S. Department of Energy (DOE) decommissioning and decontamination fees; and brokers' quotes for short-term debt, long-term debt and preferred stock and preferred securities.

Quoted market prices are used to determine the fair values of trading instruments. 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.

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

Note 4. Debt and Lines of Credit

Long-Term Debt

MEHC used the common stock of EME as security for MEHC's corporate debt obligations. MEHC's senior secured notes and credit agreement are non-recourse to Edison International and EME, and accordingly, Edison International and EME have no obligations under these instruments.

MEHC's consolidated debt at December 31, 2002 was $7.2 billion, including $911 million of debt maturing in December 2003 that is owed by EME's largest subsidiary, Edison Mission Midwest Holdings. Edison Mission Midwest Holdings is not expected to have sufficient cash to repay the $911 million debt due in December 2003. Edison Mission Midwest Holdings plans to extend or refinance the $911 million debt obligation prior to its expiration in December 2003. At December 31, 2002, Edison Mission Midwest Holdings had cash and cash equivalents of $320 million and $50 million deposited into a restricted cash account. EME believes that Edison Mission Midwest Holdings will generate positive cash flow from operations during 2003 which, in combination with its existing cash position, will contribute positively to discussions with lenders to extend or refinance the $911 million debt obligation. Completion of this extension or refinancing is subject to a number of uncertainties, including the ability of the Illinois plants to generate funds during 2003 and the availability of new credit from financial institutions on acceptable terms in light of industry conditions. Accordingly, there is no assurance that Edison Mission Midwest Holdings will be able to extend or refinance this debt when it becomes due or that the terms will not be substantially different from those under the current credit facility.

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 used 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 $550 million of pollution-control bonds in December 2000 and early 2001 that could not be remarketed in accordance with their terms. On March 1, 2002, SCE remarketed $196 million of the pollution-control bonds that SCE had repurchased in late 2000.

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

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 collateralized by the transition property and are not collateralized by, or payable from, assets of SCE or Edison International. SCE used the proceeds from the sale of the transition property to retire debt and equity securities. Although, as required by accounting principles generally accepted in the United States, SCE Funding LLC is consolidated with SCE and the rate reduction notes are shown as long-term debt in the consolidated financial statements, SCE Funding LLC is legally separate from SCE. The assets of SCE Funding LLC are not available to creditors of SCE or Edison International and the transition property is legally not an asset of SCE or Edison International.

Long-term debt is:

In millions December 31,	**2002**	2001
First and refunding mortgage bonds:		
2002-2026 (5.625% to 7.25% and variable)	**$ 2,275**	$ 1,175
Rate reduction notes:		
2002-2007 (6.22% to 6.42%)	**1,232**	1,478
Pollution-control bonds:		
2005-2040 (5.125% to 7.2% and variable)	**1,216**	1,216
Bonds repurchased	**(354)**	(550)
Funds held by trustees	**(21)**	(20)
Debentures and notes:		
2001-2039 (5.75% to 13.5% and variable)	**9,922**	10,774
Subordinated debentures:		
2044 (8.375%)	**100**	100
Commercial paper for nuclear fuel	**—**	60
Capital lease obligation	**—**	1
Long-term debt due within one year	**(2,761)**	(1,499)
Unamortized debt discount – net	**(52)**	(61)
Total	**$ 11,557**	$ 12,674

Long-term debt maturities and sinking-fund requirements for the next five years are: 2003 – $2.8 billion; 2004 – $2.8 billion; 2005 – $1.4 billion; 2006 – $895 million; and 2007 – $658 million.

On February 24, 2003, SCE completed an exchange offer of the $1.0 billion of variable rate notes due November 2003. A total of $966 million of these notes were exchanged for $966 million of a new series of first and refunding mortgage bonds due February 2007. The new debt was issued with an 8% interest rate. Approximately $34 million of the exchanged variable rate notes remain outstanding and are due in November 2003.

Through March 27, 2003, Edison International completed the purchase of $132 million of its outstanding $750 million notes due in 2004.

To isolate EME from 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 that does not have substantially similar provisions in its organizational documents; institute or consent to bankruptcy, insolvency or similar proceedings; or declare or pay dividends unless certain conditions exist. Such conditions are that EME has an investment grade rating and receives rating agency confirmation that the dividend will not result in a downgrade, or such dividends do not exceed $32.5 million in any quarter and EME meets an interest coverage ratio of 2.2 to 1 for the immediately preceding four quarters.

On March 14, 2003, an indirect subsidiary of EME received a letter from the trustee for £400 million ($644 million at December 31, 2002) in bonds related to the First Hydro project, requesting that the subsidiary engage in a process to determine whether an early redemption option in favor of the bondholders has been triggered. See Note 15, Subsequent Event, for further discussion of this matter.

Short-Term Debt

Short-term debt is used to finance fuel inventories, balancing account undercollections and general cash requirements, including power purchase payments. At December 31, 2001, commercial paper intended to finance nuclear fuel scheduled to be used more than one year after the balance sheet date was classified as long-term debt in connection with refinancing terms under five-year term lines of credit with commercial banks.

Short-term debt is:

In millions December 31,	**2002**	2001
Commercial paper	**$ —**	$ 531
Bank loans	—	1,650
Floating rate notes	**78**	—
Amount reclassified as long-term	—	(60)
Unamortized discount	—	—
Other short-term debt	—	324
Total	**$ 78**	$2,445
Weighted-average interest rate	**6.1%**	5.4%

Lines of Credit

At December 31, 2002, Edison International's subsidiaries had short-term and long-term lines of credit totaling $787 million, with various expiration dates, and when available, can be drawn down at negotiated or bank index rates. Of the total lines of credit, $512 million are long-term. EME had total lines of credit of $487 million, with $355 million available to finance general cash requirements. SCE had a fully drawn long-term line of credit of $300 million.

Note 5. 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: 2003 – $9 million; 2004 – $9 million; 2005 – $9 million; 2006 – $9 million; and 2007 – $9 million.

SCE's cumulative preferred stocks are:

Dollars in millions, except per share amounts	December 31, 2002 Shares Outstanding	December 31, 2002 Redemption Price	2002	2001
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	—	—	**—**	100
7.23	807,000	100.00	**81**	81
Preferred stock to be redeemed within one year			**(9)**	(105)
Total			**$ 147**	$ 151

In 2002, SCE redeemed 1,000,000 shares of 6.45% Series preferred stock. There were no other redemptions, and no issuances, of preferred stock in the last three years.

The 7.23% Series preferred stock has mandatory sinking funds, requiring SCE to redeem at least 50,000 shares per year from 2002 through 2006, and 750,000 shares in 2007. However, SCE is allowed to credit previously repurchased shares against the mandatory sinking fund provisions. Since SCE had previously repurchased 193,000 shares of this series, no shares were redeemed in 2002. At December 31, 2002, SCE had 143,000 of previously repurchased, but not retired, shares available to credit against the mandatory sinking fund provisions.

Company–Obligated Mandatorily Redeemable Securities of Subsidiary

In November 1994, EME issued, through a limited partnership, 3.5 million shares of 9.875% cumulative monthly income preferred securities, at a price of $25 per security and invested the proceeds in 9.875% junior subordinated deferrable interest debentures due 2024. These securities are redeemable at the option of the partnership (EME is the sole general partner), 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. In August 1995, EME also issued, through a limited partnership, 2.5 million shares of 8.5% cumulative monthly income preferred securities, at a price of $25 per security and invested the proceeds in 8.5% junior subordinated deferrable interest debentures due 2025. 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. EME issued a guarantee in favor of its preferred securities holders, which ensures the payments of distributions declared on the preferred securities, payments upon liquidation of the limited partnership and payments on redemption for securities called for redemption by the limited partnership.

EME has the right from time to time to extend the interest payment period on its junior subordinated deferrable interest debentures to a period not exceeding 60 consecutive months, at the end of which all accrued and unpaid interest will be paid in full. If EME does not make interest payments on its junior subordinated debentures, it is expected that Mission Capital will not declare or pay distributions on its cumulative monthly income preferred securities. During an extension period, EME may not do any of the following:

- declare or pay any dividend on, or purchase, acquire or make a distribution or liquidation payment with respect to, any of its common or preferred stock;
- acquire for cash or other property any indebtedness of any affiliate of EME (other than affiliates of EME which meet specified requirements) for money borrowed; or
- make any loan or advance to, or guarantee or become contingently liable in respect of indebtedness of, any affiliate of EME (other than affiliates of EME which meet specified requirements).

Furthermore, as long as any preferred securities remain outstanding, EME will not be able to declare or pay dividends on, or purchase, any of its common stock if at such time it is in default on its payment obligations under the guarantee or the subordinated indenture unless EME has given notice of the extended interest payment period described above. No securities have been redeemed as of December 31, 2002.

In 1999, Edison International (the parent company) 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 have a stated maturity of October 2029, but are redeemable at the option of Edison International, in whole or in part, beginning October 2004. Both of these securities are guaranteed by Edison International. In order to reduce its cash requirements, in May 2001, the parent company deferred the interest payments in accordance with the terms of its outstanding quarterly income debt securities issued to an affiliate. This caused a corresponding deferral of distributions on quarterly income preferred securities issued by the affiliate. Interest payments may be deferred for up to 20 consecutive quarters. During the deferral period, the principal of the debt securities and each unpaid interest installment will continue to accrue interest at the applicable coupon rate. All interest in arrears must be paid in full at the end of the deferral period. The parent company cannot pay dividends on or purchase its common stock while interest is being deferred.

Other Preferred Securities

In December 2000, EME's 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. These shares (600 Series A and 600 Series B, with a dividend rate of 5.74%) were issued during 1999, through an indirect affiliate of EME. 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.

In 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%). These shares were redeemable at their issuance price in June 2003.

In 1999, EME issued through an indirect 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 were 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).

On July 2, 2001, EME redeemed the Class A redeemable preferred shares at 10,000 New Zealand dollars per share and the retail redeemable preferred shares at one New Zealand dollar per share.

During 2001, a subsidiary of EME issued $104 million of redeemable preferred shares (250 million shares at a price of one New Zealand dollar per share with a dividend rate of 6.03%). The shares are redeemable in July 2006 at issuance price. Optional early redemption may occur if the holders pass an extraordinary resolution to redeem the shares if the subsidiary ceases to be an EME subsidiary or in the case of certain defaults of the security trust deed. The security trust deed secures a limited recourse guarantee by an EME subsidiary's payment obligations to holders of the redeemable preferred shares.

Note 6. Income Taxes

Edison International's eligible subsidiaries are included in Edison International's consolidated federal income tax and combined state franchise tax returns. Edison International has tax-allocation and payment agreements with certain of its subsidiaries. For subsidiaries other than SCE, the right of a participating subsidiary to receive or make a payment and the amount and timing of tax-allocation payments are dependent on the inclusion of the subsidiary in the consolidated income tax returns of Edison International and other factors including, the consolidated taxable income of Edison International and its includible subsidiaries, the amount of taxable income or net operating losses and other tax items of the participating subsidiary, as well as the other subsidiaries of Edison International. There are specific procedures regarding allocations of state taxes. Each subsidiary is eligible to receive tax-allocation payments for its tax losses or credits only at such time as Edison International and its subsidiaries generate sufficient taxable income to be able to utilize the participating subsidiary's losses in the consolidated tax return of Edison International. Under an income tax-allocation agreement approved by the CPUC, SCE's tax liability is computed as if it filed a separate return.

As part of the process of preparing its consolidated financial statements, Edison International is required to estimate its income taxes in each of the jurisdictions in which it operates. This process involves estimating actual current tax exposure together with assessing temporary differences resulting from differing treatment of items, such as depreciation, for tax and accounting purposes. These differences result in deferred tax assets and liabilities, which are included within Edison International's consolidated balance sheet. Edison International's subsidiaries do not provide for federal income taxes or tax benefits on the undistributed earnings or losses of their international subsidiaries because such earnings are reinvested indefinitely.

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 sources of income (loss) from continuing operations before income taxes are:

In millions	Year ended December 31,	**2002**	2001	2000
Domestic		**$ 1,379**	$ 3,962	$ (3,101)
Foreign		**147**	87	143
Total		**$ 1,526**	$ 4,049	$ (2,958)

The components of income tax expense (benefit) on income (loss) from continuing operations by location of taxing jurisdiction are:

In millions	Year ended December 31,	**2002**	2001	2000
Current:				
Federal		**$ 585**	$ (215)	$ (61)
State		**111**	—	—
Foreign		**38**	30	70
		734	(185)	9
Deferred:				
Federal		**(312)**	1,422	(887)
State		**(43)**	406	(134)
Foreign		**12**	4	(7)
		(343)	1,832	(1,028)
Total		**$ 391**	$ 1,647	$ (1,019)

The components of deferred tax expense (benefit) from continuing operations, which arise from tax credits and timing differences between financial and tax reporting, are:

In millions Year ended December 31,	2002	2001	2000
Deferred – federal, state and foreign:			
Accrued charges	**$ 59**	$ (79)	$ (98)
Depreciation and basis differences	**230**	165	(5)
Investment and energy tax credits – net	**(7)**	(6)	(41)
Leveraged leases	**100**	320	387
Loss carryforwards	**—**	36	(812)
Regulatory balancing accounts	**(575)**	1,345	(740)
CTC amortization	**(99)**	(138)	251
Pension reserves	**34**	(4)	1
Price risk management	**25**	39	(38)
State tax privilege year	**(78)**	(41)	30
Unbilled revenue	**—**	101	20
Other	**(32)**	94	17
Total	**$ (343)**	$ 1,832	$ (1,028)

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

In millions December 31,	2002	2001
Deferred tax assets:		
Property-related	**$ 178**	$ 192
Unrealized gains or losses	**274**	310
Investment tax credits	**73**	72
Regulatory balancing accounts	**5,365**	1,709
Deferred income	**172**	179
Accrued charges	**501**	490
Loss carryforwards	**448**	752
Other	**240**	344
Subtotal	**7,251**	4,048
Valuation allowance	**(21)**	(25)
Total	**$ 7,230**	$ 4,023
Deferred tax liabilities:		
Property-related	**$ 3,976**	$ 3,643
Leveraged leases	**2,044**	1,972
Capitalized software costs	**204**	224
Regulatory balancing accounts	**6,054**	2,929
Unrealized gains and losses	**171**	208
Other	**353**	322
Total	**$12,802**	$ 9,298
Accumulated deferred income taxes – net	**$ 5,572**	$ 5,275
Classification of accumulated deferred income taxes:		
Included in deferred credits	**$ 5,842**	$ 6,367
Included in current assets	**$ 270**	$ 1,092

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

Year ended December 31,	**2002**	2001	2000
Federal statutory rate	**35.0%**	35.0%	35.0%
Foreign earnings reinvestment	**(0.8)**	(0.3)	0.4
Housing credits	**(2.4)**	(1.2)	2.1
Capitalized software	**—**	—	0.4
Property-related and other	**(7.2)**	1.1	(7.9)
Investment and energy tax credits	**(0.3)**	(0.2)	1.4
Favorable resolution of audit	**(2.4)**	—	—
State tax – net of federal deduction	**3.7**	6.3	3.0
Effective tax rate	**25.6%**	40.7%	34.4%

Edison International's composite federal and state statutory tax rate was approximately 40.5% for all years presented. The lower effective tax rate of 25.6% realized in 2002 was primarily due to: reestablishing a tax related regulatory asset at SCE due to implementation of the CPUC's URG decision; a favorable adjustment to Edison Capital's cumulative deferred taxes for changes in its effective state tax rate; the benefits received from low income housing and production tax credits at Edison Capital; recording the benefit of favorable settlements of Internal Revenue Service (IRS) audits at SCE; and the effect of lower foreign tax rates and permanent reinvestment of earnings of foreign affiliates at EME, offset by foreign losses which were not able to be utilized in the current period.

At December 31, 2002, Edison International and its subsidiaries have federal and state tax credits of $228 million which expire between 2018 and 2021, California net operating loss carryforwards of $1.2 billion which expire between 2009 and 2011, and California capital loss carryforwards of $165 million which expire in 2005. In addition, EME has foreign and separate state net operating loss carryforwards.

As a matter of course, Edison International is regularly audited by federal, state and foreign taxing authorities. For further discussion of this matter, see "Federal Income Taxes" in Note 10.

Note 7. 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 $42 million in 2002, $40 million in 2001 and $41 million in 2000.

Pension Plan and Postretirement Benefits Other Than Pensions

Edison International has defined-benefit pension plans (some with cash balance features), including executive and non-executive plans, which cover U.S. employees meeting minimum service and other requirements. SCE recognizes pension expense for its non-executive plan as calculated by the actuarial method used for ratemaking. Certain foreign subsidiaries of EME also participate in their own respective defined-benefit pension plans.

Most U.S. 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.

EME's Ferrybridge and Fiddler's Ferry employees joined a separate defined benefit pension plan during first quarter 2000. In December 2001, the Ferrybridge and Fiddler's Ferry plants were sold to two wholly owned subsidiaries of American Electric Power. American Electric Power hired EME's employees upon completion of the purchase and was required, in accordance with the asset purchase agreement, to set up a pension plan similar to EME's by March 31, 2002. All of EME's former employees transferred to the new plan as of December 20, 2002. In accordance with accounting standards, Edison International recorded a curtailment gain of approximately $10 million related to the cessation of future benefits for EME's former employees in 2001. The curtailment gain reduced actuarial losses incurred during the year and, therefore, did not impact Edison International's pension expense.

The curtailment/settlement of postretirement employee benefits liability relates to a retirement health care and other benefits plan for represented employees at the EME's Midwest Generation unit that expired on June 15, 2002. In October 2002, Midwest Generation reached an agreement with its union-represented employees on new benefits plans, for the period of January 1, 2003 through June 30, 2005. Midwest Generation continued to provide benefits at the same level as those in the expired agreement until December 31, 2002. The accounting for postretirement benefits liabilities has been determined on the basis of a substantive plan under applicable accounting rules. A substantive plan means that Midwest Generation assumed, for accounting purposes, that it would provide postretirement health care benefits to union-represented employees following conclusion of negotiations to replace the current benefits agreement, even though Midwest Generation had no legal obligation to do so. Under the new agreement, postretirement health care benefits will not be provided. Accordingly, Midwest Generation treated this as a plan termination and recorded a pre-tax gain of $71 million during fourth quarter 2002.

At December 31, 2002, the accumulated benefit obligation of the executive pension plan and the plans at two EME subsidiaries exceeded the related plan assets at the measurement date. In accordance with accounting standards, Edison International recorded an additional minimum liability of $33 million, with corresponding charges of $4 million as an intangible asset and $29 million as a reduction to shareholder's equity through a charge to accumulated other comprehensive income. The charge to accumulated other comprehensive income would be restored through shareholders' equity in future periods to the extent the fair value of the plan assets exceed the accumulated benefit obligation.

The projected benefit obligation, accumulated benefit obligation and fair value of plan assets for pension plans with accumulated benefit obligations in excess of plan assets were $188 million, $147 million and $51 million, respectively, as of December 31, 2002, and $80 million, $58 million and zero, respectively, as of December 31, 2001. As of December 31, 2002 and 2001, the fair value of plan assets exceeded the accumulated benefit obligation for all other pension plans.

Information on plan assets and benefit obligations for United States employees is shown below:

In millions Year ended December 31,	Pension Benefits 2002	Pension Benefits 2001	Other Postretirement Benefits 2002	Other Postretirement Benefits 2001
Change in projected benefit obligation				
Benefit obligation at beginning of year	**$ 2,480**	$ 2,343	**$ 2,053**	$ 1,890
Service cost	**86**	82	**49**	50
Interest cost	**165**	164	**141**	137
Actuarial loss	**104**	82	**82**	47
Amendments	**3**	—	**—**	—
Curtailment/settlement	**—**	—	**(74)**	—
Benefits paid	**(144)**	(191)	**(80)**	(71)
Projected benefit obligation at end of year	**$ 2,694**	$ 2,480	**$ 2,171**	$ 2,053
Change in plan assets				
Fair value of plan assets at beginning of year	**$ 2,768**	$ 3,109	**$ 1,139**	$ 1,200
Actual return on plan assets	**(316)**	(165)	**(148)**	(92)
Employer contributions	**14**	15	**161**	102
Benefits paid	**(144)**	(191)	**(80)**	(71)
Fair value of plan assets at end of year	**$ 2,322**	$ 2,768	**$ 1,072**	$ 1,139
Funded status	**$ (372)**	$ 288	**$(1,099)**	$ (914)
Unrecognized net loss (gain)	**439**	(201)	**715**	407
Unrecognized transition obligation	**12**	18	**269**	296
Unrecognized prior service cost	**101**	112	**(2)**	(3)
Recorded asset (liability)	**$ 180**	$ 217	**$ (117)**	$ (214)
Discount rate	**6.5%**	7.0%	**6.75%**	7.25%
Rate of compensation increase	**5.0%**	5.0%	**—**	—
Expected return on plan assets	**8.5%**	8.5%	**8.2%**	8.2%

Expense components are:

In millions Year ended December 31,	Pension Benefits 2002	Pension Benefits 2001	Pension Benefits 2000	Other Postretirement Benefits 2002	Other Postretirement Benefits 2001	Other Postretirement Benefits 2000
Service cost	**$ 86**	$ 82	$ 78	**$ 49**	$ 50	$ 45
Interest cost	**165**	164	164	**141**	137	129
Expected return on plan assets	**(228)**	(255)	(270)	**(93)**	(98)	(106)
Special termination benefits	**—**	13	—	**—**	2	—
Curtailment/settlement	**—**	—	—	**(71)**	—	—
Net amortization and deferral	**22**	(6)	(37)	**37**	27	27
Expense under accounting standards	**45**	(2)	(65)	**63**	118	95
Regulatory adjustment – deferred	**(18)**	39	88	**—**	—	—
Total expense recognized	**$ 27**	$ 37	$ 23	**$ 63**	$ 118	$ 95

The assumed rate of future increases in the per-capita cost of health care benefits is 9.75% for 2003, 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, 2002 by $355 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, 2002 by $286 million and annual aggregate service costs by $27 million.

Information on pension plan assets and benefit obligation for foreign employees is shown below:

In millions Year ended December 31,	2002	2001
Change in projected benefit obligation		
Benefit obligation at beginning of year	**$ 114**	$ 126
Service cost	**2**	3
Interest cost	**8**	6
Actuarial loss (gain)	**(4)**	(21)
Curtailment/settlement	**(53)**	—
Plan participants' contribution	**1**	2
Benefits paid	**(2)**	(2)
Projected benefit obligation at end of year	**$ 66**	$ 114
Change in plan assets		
Fair value of plan assets at beginning of year	**$ 110**	$ 123
Actual return on plan assets	**(18)**	(19)
Employer contributions	**4**	7
Curtailment/settlement	**(51)**	—
Plan participants' contribution	**—**	1
Benefits paid	**(2)**	(2)
Fair value of plan assets at end of year	**$ 43**	$ 110
Funded status	**$ (23)**	$ (4)
Unrecognized net loss	**19**	10
Recorded asset (liability)	**$ (4)**	$ 6
Discount rate	**5.0% to 5.50%**	4.0% to 6.0%
Rate of compensation increase	**3.5% to 4.0%**	3.5% to 4.0%
Expected return on plan assets	**7.5% to 8.0%**	8.0%

Pension expense components for foreign employees are:

In millions Year ended December 31,	2002	2001	2000
Service cost	**$ 2**	$ 3	$ 3
Interest cost	**8**	6	7
Expected return on plan assets	**(10)**	(7)	(7)
Net amortization and deferral	**15**	—	—
Total expense recognized	**$ 15**	$ 2	$ 3

Long-Term Incentive Plans

Phantom Stock Options

Phantom stock option performance awards were granted through 1999 at EME and Edison Capital as part of the Edison International long-term incentive compensation program for senior management. In August 2000, all outstanding phantom options were exchanged for a combination of cash and stock equivalent units relating to Edison International common stock, in accordance with the EME and Edison Capital affiliate option exchange offers. Compensation expense recorded for the phantom stock options was $3 million in 2002, $7 million in 2001 and $13 million in 2000. In 2000, compensation expense was adjusted. Due to the lower valuation of the exchange offer, compared to the values previously accrued, the liability for accrued incentive compensation was reduced by approximately $60 million.

Stock-Based Employee Compensation

In 1998, Edison International shareholders approved the Edison International Equity Compensation Plan, replacing the long-term incentive compensation program that had been adopted by Edison International shareholders in 1992. The 1998 plan authorizes a limited annual number of Edison International common shares that may be issued in accordance with plan awards. The annual authorization is cumulative, allowing subsequent issuance of previously unutilized awards. In May 2000, the Edison International Board of Directors adopted an additional plan, the 2000 Equity Plan, under which stock options, including the special options discussed below, may be awarded.

Under the 1992, 1998 and 2000 plans, options on 11.8 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 generally expire 10 years after date of grant and vest over a period of up to five years.

Edison International stock options awarded prior to 2000 include a dividend equivalent feature. Dividend equivalents on stock options issued after 1993 and prior to 2000 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 include a dividend equivalent feature.

Options issued after 1997 generally have a four-year vesting period. The special options granted in 2000 vest over five years, in 25% increments beginning in May 2002. Earlier options had a three-year vesting period with one-third of the total award vesting annually. If an option holder retires, dies, is terminated by the company, or is terminated while 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 except that in the case of termination by the company where the option holder is not eligible for retirement, vested options are forfeited unless exercised within one year of termination date. If an option holder is terminated other than by a qualifying event, options that 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 fair value for each option granted, reflecting the basis for the pro forma disclosures in Note 1 was determined on the date of grant using the Black-Scholes option-pricing model. The following assumptions are used in determining fair value through the model:

December 31,	**2002**	2001	2000
Expected life	**7 years – 10 years**	7 years – 10 years	7 years – 10 years
Risk-free interest rate	**4.7% to 6.1%**	4.7% to 6.1%	4.7% to 6.0%
Expected dividend yield	**1.8%**	3.3%	4.5%
Expected volatility	**18% to 54%**	17% to 52%	17% to 46%

The expected dividend yield above is computed using an average of the previous 12 quarters. The expected volatility above is computed on a historical 36-month basis.

The application of fair-value accounting to calculate the pro forma disclosures 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, Dec. 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, Dec. 31, 2000	19,774,672	$14.56–$29.34	$ 22.24		8 years
Granted	1,001,704	$ 9.10–$15.92	$ 10.90	$ 3.88	
Expired	(74,512)	$18.75–$19.35	$ 18.79		
Forfeited	(11,407,835)	$ 9.15–$29.34	$ 20.91		
Exercised	—	—	—		
Outstanding, Dec. 31, 2001	9,294,029	$ 9.10–$29.34	$ 22.45		6 years
Granted	3,450,393	$ 8.90–$19.45	$ 18.59	$ 7.88	
Expired	(520,706)	$ 9.57–$29.34	$ 23.34		
Forfeited	(318,980)	$ 9.10–$28.13	$ 17.43		
Exercised	(68,444)	$ 9.15–$16.59	$ 12.45		
Outstanding, Dec. 31, 2002	11,836,292	$ 8.90–$29.25	$ 21.46		6 years

The number of options exercisable and their weighted-average exercise prices at December 31, 2002, 2001 and 2000 were 6,475,029 at $23.61, 5,930,024 at $22.92 and 6,782,209 at $23.27, respectively.

Other Equity-Based Awards

For the years after 1999, a portion of the executive long-term incentives was awarded in the form of performance shares. The 2000 performance shares were restructured as retention incentives in December 2000, which pay as a combination of Edison International common stock and cash if the executive remains employed at the end of the performance period. The performance period ended December 31, 2001, for half the award, and ends December 31, 2002 for the remainder. Additional performance shares were awarded in January 2001 and January 2002. The 2001 performance shares vest December 31, 2003, half in shares of Edison International common stock and half in cash. The 2002 performance shares vest December 31, 2004, also half in shares of common stock and half in cash. The number of shares that will be paid out from the 2002 performance share awards will depend on the performance of Edison International common stock relative to the stock performance of a specific group of peer companies. The 2000 and 2001 performance shares and deferred stock unit values are accrued ratably over a three-year performance period. The 2002 performance shares will be valued based on Edison International's stock performance relative to the stock performance of other such entities.

In March 2001, deferred stock units were awarded as part of a retention program. These vest and were paid on March 12, 2003 in shares of Edison International common stock.

In October 2001, a stock option retention exchange offer was extended, offering holders of Edison International stock options granted in 2000 the opportunity to exchange those options for a lesser number of deferred stock units. The exchange ratio was based on the Black-Scholes value of the options and the stock price at the time the offer was extended. The exchange took place in November 2001; the options that participants elected to exchange were cancelled, and deferred stock units were issued. Approximately three options were cancelled for each deferred stock unit issued. Twenty-five percent of the deferred stock units will vest and be paid in Edison International common stock per year over four years, with the first vesting and payment date in November 2002. The following assumptions were used in determining fair value through the Black-Scholes option-pricing model: expected life – 8 to 9 years; risk-free interest rate – 5.10%; expected volatility – 52%.

See Note 1 for Edison International's accounting policy and expenses related to stock-based employee compensation.

Note 8. 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, 2002 is:

In millions	Investment in Facility	Accumulated Depreciation and Amortization	Ownership Interest
Transmission systems:			
Eldorado	$ 45	$ 12	60%
Pacific Intertie	246	86	50
Generating stations:			
Four Corners Units 4 and 5 (coal)	480	374	48
Mohave (coal) (1)	341	253	56
Palo Verde (nuclear)(2)	1,631	1,424	16
San Onofre (nuclear)(2)	4,305	3,859	75
Total	$ 7,048	$ 6,008	

(1) A portion is included in regulatory assets on the consolidated balance sheet. See Note 1.
(2) Included in regulatory assets on the consolidated balance sheet.

Note 9. Commitments

Leases

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

During 2001, EME entered into a sale-leaseback of its Homer City facilities to third-party lessors for an aggregate purchase price of $1.6 billion, consisting of $782 million in cash and assumption of debt (with fair value of $809 million).

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 on the sale of the facilities, power plant and equipment has been deferred and is being amortized over the terms of the respective leases.

Estimated remaining commitments for noncancelable leases at December 31, 2002 are:

Year ended December 31,	In millions
2003	$ 356
2004	332
2005	371
2006	451
2007	485
Thereafter	5,065
Total	$ 7,060

Operating lease expense was $249 million in 2002, $182 million in 2001 and $142 million in 2000.

Nuclear Decommissioning

Decommissioning is estimated to cost $2.5 billion in current-year dollars, based on site-specific studies performed in 2001 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 $11.8 billion through 2060 to decommission its nuclear facilities. This estimate is based on SCE's current–dollar decommissioning costs, escalated at rates ranging from 0.9% 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 3.7% to 6.4%. If the assumed return on trust assets is not earned, it is probable that additional funds needed for decommissioning will be recoverable through rates.

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. The estimated remaining cost to decommission San Onofre Unit 1 is recorded as a liability ($298 million at December 31, 2002). Total expenditures for the decommissioning of San Onofre Unit 1 were $197 million through December 31, 2002.

SCE plans to decommission its nuclear generating facilities by a prompt removal method authorized by the Nuclear Regulatory Commission. Decommissioning is expected to begin after the plants' operating licenses expire. The operating licenses expire in 2022 for San Onofre Units 2 and 3, and in 2026 and 2028 for the Palo Verde units. 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 expense was $73 million in 2002, $96 million in 2001 and $106 million in 2000. The accumulated provision for decommissioning, excluding San Onofre Unit 1 and unrealized holding gains, was $1.6 billion at December 31, 2002 and $1.5 billion at December 31, 2001.

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,	**2002**	2001
Municipal bonds	2002 – 2039		**$ 442**	$ 463
Stocks	–		**752**	637
U.S. government issues	2002 – 2032		**252**	332
Short-term and other	2002 – 2003		**321**	334
Total			**$ 1,767**	$ 1,766

Trust fund earnings (based on specific identification) increase the trust fund balance and the accumulated provision for decommissioning. Net earnings (loss) were $(25) million in 2002, $13 million in 2001 and $38 million in 2000. Proceeds from sales of securities (which are reinvested) were $3.3 billion in 2002, $3.9 billion in 2001 and $4.7 billion in 2000. Approximately 91% of the cumulative 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 gas and coal fuel contracts require payment of certain fixed charges whether or not gas or coal is delivered.

SCE has purchase-power contracts with certain QFs (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. In an effort to replace higher-cost contract payments with lower-cost replacement power, SCE has entered into purchased-power settlements to end its contract obligations with certain QFs. The settlements are reported as power-purchase contracts on the balance sheets.

At December 31, 2002, EME had contractual commitments of $237 million to transport natural gas beginning the later of May 1, 2003, or the first day that expansion capacity is available for transportation services. EME is committed to pay minimum fees under these agreements, which have a term of 15 years.

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 $134 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 $30 million). The transmission service contract requires a minimum payment of approximately $6 million a year.

Certain commitments for the years 2003 through 2007 are estimated below:

In millions	2003	2004	2005	2006	2007
Fuel supply contracts	$ 760	$ 605	$ 574	$ 490	$ 353
Gas transportation payments	8	16	16	16	15
Purchased-power capacity payments	597	595	578	543	543

EME has firm commitments related to the Italian Wind projects for asset purchases of $2 million and equity and other contributions to its projects of $75 million, primarily for the CBK and Sunrise projects. EME also has contingent obligations to make additional contributions of $44 million, primarily for equity support guarantees related to the Paiton project in Indonesia and ISAB project in Italy. EME has total firm commitments of $24 million for capital improvements (includes environmental and non-environmental).

For the CBK project, equity was initially expected to be contributed through December 2003 upon full draw-down of the project's debt facility, which had been scheduled for late 2002. During the fourth quarter of 2002, EME prepaid $11 million of the equity contribution as a result of a failure by the contractor responsible for engineering, procurement and construction of the project to provide additional security for liquidated damages. EME has obtained a waiver from lenders for the contractor's default, but expects that equity will be fully contributed before the project is able to draw upon the remaining loan commitment. In addition, as a result of Moody's credit downgrade, EME posted a $42 million letter of credit to support the remaining portion of this obligation. In addition to these equity infusions, the project sponsors funded a special draw in December 2001 (EME's share of which was $10 million), as a one-time adjustment to the construction payment schedule and loan draw down schedule agreed among the project, the sponsors and the contractor.

Firm commitments to contribute project equity to the CBK and Italian Wind projects could be accelerated due to events of default.

As of December 31, 2002, Edison Capital had outstanding commitments of $21 million to fund affordable housing projects, and $134 million for energy and infrastructure investments. Prior to funding any commitments, specific contract conditions must be satisfied. At December 31, 2002, as a result of Edison Capital's financial condition, it has deposited approximately $7 million as collateral for several letters of credit currently outstanding.

EME's Guarantees and Indemnities

Tax Indemnity Agreements

In connection with the sale-leaseback transactions that EME has entered into related to the Collins Station, Powerton and Joliet plants in Illinois and the Homer City facilities in Pennsylvania, EME or one of its subsidiaries has entered into tax indemnity agreements. Under these tax indemnity agreements, EME has agreed to indemnify the lessors in the sale-leaseback transactions for specified adverse tax consequences that could result in certain situations set forth in each tax indemnity agreement, including specified defaults under the respective leases. The potential indemnity obligations under these tax indemnity agreements could be significant. Due to the nature of these obligations under these tax indemnity agreements, EME cannot determine a maximum potential liability. The indemnities would be triggered by a valid claim from the lessors. EME has not recorded a liability related to these indemnities.

Indemnities Provided as Part of EME's Acquisitions

In connection with the acquisition of the Illinois plants and the Homer City project, EME agreed to indemnify the sellers against damages, claims, fines, liabilities and expenses and losses arising from, among other things, environmental liabilities before and after the date of each sale as specified in the specific asset sale agreements (August 1, 1998 for Homer City and March 22, 1999 for the Illinois plants). In the case of the Illinois plants, the indemnification claims are reduced by any insurance proceeds and tax benefits related to such claims and are subject to a requirement by the seller to take all reasonable steps to mitigate losses related to any such indemnification claim. Due to the nature of the obligation under these indemnities, a maximum potential liability cannot be determined. Each of these indemnifications is not limited in term and would be triggered by a valid claim from the respective seller. Except as discussed below, EME has not recorded a liability related to these indemnities.

Midwest Generation (EME's subsidiary that is operating the Illinois plants) entered into a supplemental agreement to resolve a dispute regarding interpretation of its reimbursement obligation for asbestos claims under the environmental indemnities set forth in the Illinois plants asset sale agreement. Under this supplemental agreement, Midwest Generation agreed to reimburse the seller 50% of specific existing asbestos claims, less recovery of insurance costs, and agreed to a sharing arrangement for liabilities associated with future asbestos related claims as specified in the agreement. The obligations under this agreement are not subject to a maximum liability. The supplemental agreement has a five-year term with an automatic renewal provision (subject to the right to terminate). Payments are made under this indemnity by a valid claim provided from the seller. At December 31, 2002, Midwest Generation recorded a $5 million liability related to known claims provided by the seller.

Indemnities Provided Under Asset Sale Agreements

In connection with the sale of assets, EME has provided indemnities to the purchasers for taxes imposed with respect to operations of the asset prior to the sale, and EME or its subsidiaries have received similar indemnities from purchasers related to taxes arising from operations after the sale. EME also provided indemnities to purchasers for items specified in each agreement (for example, specific pre-existing litigation matters and/or environmental conditions). Due to the nature of the obligations under these indemnity agreements, a maximum potential liability cannot be determined. Indemnities under the asset sale agreements do not have specific expiration dates. Payments would be triggered under these indemnities by valid claims from the sellers or purchasers, as the case may be. EME has not recorded a liability related to these indemnities.

Guarantee of 50% of TM Star Fuel Supply Obligations

TM Star was formed for the limited purpose to sell natural gas to the March Point Cogeneration Company, an affiliate through common ownership, under a fuel supply agreement that extends through December 31, 2011. TM Star has entered into fuel purchase contracts with unrelated third parties to meet a portion of the obligations under the fuel supply agreement. EME has guaranteed 50% of TM Star's obligation under the fuel supply agreement to March Point Cogeneration. Due to the nature of the obligation under this guarantee, a maximum potential liability cannot be determined. TM Star has met its obligations to March Point Cogeneration, and, accordingly, no claims against this guarantee have been made.

Capacity Indemnification Agreements

EME has guaranteed, jointly and severally with Texaco Inc., the obligations of March Point Cogeneration Company under its project power sales agreements to repay capacity payments to the project's power purchaser in the event that the power sales agreement terminates, March Point Cogeneration Company abandons the project, or the project fails to return to normal operations within a reasonable time after a complete or partial shutdown, during the term of the power contracts. In addition, subsidiaries of EME have guaranteed the obligations of Kern River Cogeneration Company and Sycamore Cogeneration Company under their project power sales agreements to repay capacity payments to the projects' power purchaser in the event that the projects unilaterally terminate their performance or reduce their electric power producing capability during the term of the power contracts. The obligations under the indemnification agreements as of December 31, 2002, if payment were required, would be $209 million. EME has no reason to believe that any of these projects will either cease operations or reduce its electric power producing capability during the term of its power contract.

Note 10. 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. Edison International believes the outcome of these other proceedings will not materially affect its results of operations or liquidity.

Aircraft Leases

Edison Capital has leased three aircraft to American Airlines. American Airlines reports significant operating losses, and there is increasing concern that American Airlines may file bankruptcy. If American Airlines files bankruptcy, or otherwise defaults in making its lease payments, the lenders with a security interest in the aircraft may exercise remedies that could lead to a loss of some or all of Edison Capital's investment in the aircraft plus any accrued interest. A voluntary restructure of the leases could also result in a loss of some or all of the investment. The total maximum loss exposure to Edison Capital is $48 million. At December 31, 2002, American Airlines was current in its lease payments and was publicly expressing a desire to avoid bankruptcy.

EME's Chicago In-City Obligation

Pursuant to the acquisition documents for the purchase of generating assets from Commonwealth Edison, EME committed to install one or more gas-fired electric generating units having an additional capacity of 500 MW at or adjacent to an existing power plant site in Chicago (this commitment is referred to as the In-City Obligation) for an estimated cost of $320 million. The acquisition documents required that commercial operation of this project commence by December 15, 2003. Due to additional capacity for new gas-fired generation and the improved reliability of power generation in the Chicago area, EME did not believe the additional gas-fired generation was needed. In February 2003, EME finalized an agreement with Commonwealth Edison to terminate this commitment in exchange for the following: payment of $22 million to Commonwealth Edison in February 2003; payment of approximately $14 million to Commonwealth Edison due in nine equal annual installments beginning in February 2004, secured by a security interest in 125,000 barrels of oil at the Collins Station; and assumption of a power purchase obligation of the City of Chicago by entering into a replacement long-term power purchase contract with Calumet Energy Team LLC. The replacement contract requires EME to pay a monthly capacity payment and gives EME an option to purchase energy from Calumet Energy Team LLC at prices based primarily on operation and maintenance and fuel costs.

As a result of this agreement with Commonwealth Edison, EME recorded a before-tax loss of $45 million during the fourth quarter of 2002. The loss was determined by the sum of: (a) the present value of the cash payments to Commonwealth Edison and Calumet Energy Team LLC (capacity payments) less (b) the fair market value of the option to purchase power under the replacement contract with Calumet Energy Team LLC. As a result of this agreement with Commonwealth Edison, EME is no longer obligated to build the additional gas-fired generation.

Energy Crisis Issue

In October 2000, a federal class action securities lawsuit was filed against SCE and Edison International. The lawsuit, as amended, involved securities fraud claims arising from alleged improper accounting for the energy-cost undercollections. The complaint was supposedly filed on behalf of a class of persons who purchased Edison International common stock between July 21, 2000 and April 17, 2001. This lawsuit was consolidated with another similar lawsuit filed on March 15, 2001. SCE and Edison International filed a motion to dismiss the lawsuits for failure to state a claim and on March 8, 2002 the district court dismissed the complaint with prejudice. The plaintiffs have dismissed their appeal and on April 26, 2002 the federal court of appeals dismissed the appeal with prejudice.

Environmental Remediation

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

Edison International records its environmental remediation liabilities when site assessments and/or remedial actions are probable and a range of reasonably likely cleanup costs can be estimated. 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 at SCE (41 sites) and EME (3 sites) is $101 million, $99 million of which is related to SCE. The sites include SCE's divested gas-fuel generation plants, for which SCE retained some liability after their sale. Edison International's other subsidiaries have no identified remediation sites. 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 $284 million, $282 million of which is related to SCE. The upper limit of this range of costs was estimated using assumptions least favorable to Edison International among a range of reasonably possible outcomes.

The CPUC allows SCE to recover environmental remediation costs at certain sites, representing $38 million of its recorded liability, through an incentive mechanism (SCE may request to include additional sites). Under this mechanism, SCE will recover 90% of cleanup costs through customer rates; shareholders fund the remaining 10%, with the opportunity to recover these costs from insurance carriers and other third parties. SCE has successfully settled insurance claims with all responsible carriers. SCE expects to recover costs incurred at its remaining sites through customer rates. SCE has recorded a regulatory asset of $70 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 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 $15 million to $25 million. Recorded costs for 2002 were $25 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 for its identified sites and, based upon the CPUC's regulatory treatment of environmental remediation costs incurred at SCE, 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.

Federal Income Taxes

In August 2002, Edison International received a notice from the IRS asserting deficiencies in federal corporate income taxes for its 1994 to 1996 tax years. The vast majority of the tax deficiencies are timing differences and, therefore, amounts ultimately paid, if any, would benefit Edison International as future tax deductions. Edison International believes that it has meritorious legal defenses to those deficiencies and believes that the ultimate outcome of this matter will not result in a material impact on Edison International's consolidated results of operations or financial position.

Among the issues raised by the IRS in the 1994 to 1996 audit was Edison Capital's treatment of the EPZ and Dutch electric locomotive leases. Written protests were filed against these deficiency notices, as well as other alleged deficiencies, asserting that the IRS's position misstates material facts, misapplies the law and is incorrect. Edison Capital will vigorously contest the assessment through administrative appeals and litigation, if necessary. Edison Capital believes it will ultimately prevail.

The IRS is also currently examining the tax returns for Edison International, which includes Edison Capital, for years 1997 through 1999. Edison Capital expects the IRS to also challenge several of its other leveraged leases based on a recent Revenue Ruling addressing a specific type of leveraged lease (termed a lease in/lease out or LILO transaction). Edison Capital believes that the position described in the Revenue Ruling is incorrect and that its leveraged leases are factually and legally distinguishable in material respects from that position. Edison Capital intends to vigorously defend, and litigate if necessary, against any challenges based on that position.

Navajo Nation Litigation

Peabody Holding Company (Peabody) supplies coal from mines on Navajo Nation lands to Mohave. In June 1999, the Navajo Nation filed a complaint in federal district court against Peabody and certain of its affiliates, Salt River Project Agricultural Improvement and Power District, and SCE. The complaint asserts claims against the defendants for, among other things, violations of the federal RICO statute, interference with fiduciary duties and contractual relations, fraudulent misrepresentation by nondisclosure, and various contract-related claims. The complaint claims that the defendants' actions prevented the Navajo Nation from obtaining the full value in royalty rates for the coal. The complaint seeks damages of not less than $600 million, trebling of that amount, and punitive damages of not less than $1 billion, as well as a declaration that Peabody's lease and contract rights to mine coal on Navajo Nation lands should be terminated.

In February 2002, Peabody and SCE filed cross claims against the Navajo Nation, alleging that the Navajo Nation had breached a settlement agreement and final award between Peabody and the Navajo Nation by filing their lawsuit.

The Navajo Nation had previously filed suit in the Court of Claims against the United States Department of Interior, alleging that the Government had breached its fiduciary duty concerning contract negotiations including the Navajo Nation and the defendants. In February 2000, the Court of Claims issued a decision in the Government's favor, finding that while there had been a breach, there was no available redress from the Government. Following appeal of that decision by the Navajo Nation, an appellate court ruled that the Court of Claims did have jurisdiction to award damages and remanded the case to the Court of Claims for that purpose. On June 3, 2002, the Government's request for review of the case by the United States Supreme Court was granted. On March 4, 2003, the Supreme Court reversed the appellate court and held that the Government is not liable to the Navajo Nation as there was no breach of a fiduciary duty and that the Navajo Nation did not have a right to relief against the Government.

SCE cannot predict with certainty the outcome of the 1999 Navajo Nation's complaint against SCE, nor the impact on this complaint or the Supreme Court's decision on the outcome of the Navajo Nation's suit against the government, or the impact of the complaint on the operation of Mohave beyond 2005.

Nuclear Insurance

Federal law limits public liability claims from a nuclear incident to $9.5 billion. SCE and other owners of the San Onofre and Palo Verde nuclear generating stations have purchased the maximum private primary insurance available ($200 million at December 31, 2002 and $300 million beginning January 1, 2003). 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. The U.S. Congress has extended the expiration date of the applicable law until December 31, 2003 and is considering amendments that, among other things, are expected to extend the law beyond 2003.

Property damage insurance covers losses up to $500 million, including decontamination costs, at San Onofre and Palo Verde. Decontamination liability and property damage coverage exceeding the primary $500 million also has been purchased in amounts greater than federal requirements. Additional insurance covers part of replacement power expenses during an accident-related nuclear unit outage. A mutual insurance company owned by utilities with nuclear facilities issues these policies. If losses at any nuclear facility covered by the arrangement were to exceed the accumulated funds for these insurance programs, SCE could be assessed retrospective premium adjustments of up to $38 million per year. Insurance premiums are charged to operating expense.

Paiton Project

A wholly owned subsidiary of EME owns a 40% interest in Paiton Energy, which owns the Paiton project, a 1,230-MW coal-fired power plant in Indonesia. Under the terms of a long-term power purchase agreement between Paiton Energy and the state-owned electric utility company, the state-owned electric utility company is required to pay for capacity and fixed operating costs once each unit and the plant achieved commercial operation.

On December 23, 2002, an amendment to the original power purchase agreement became effective, bringing to a close and resolving a series of disputes between Paiton Energy and the state-owned electric utility company which began in 1999 and were caused, in large part, by the effects of the regional financial crisis in Asia and Indonesia. The amended power purchase agreement includes changes in the price for power and energy charged under the power purchase agreement, provides for payment over time of amounts unpaid prior to January 2002 and extends the expiration date of the power purchase agreement from 2029 to 2040. These terms have been in effect since January 2002 under a previously agreed binding term sheet, which was replaced by the power purchase agreement amendment.

In February 2003, Paiton Energy and all of its lenders concluded a restructuring of the project's debt. As part of the restructuring, the Export-Import Bank of the United States loaned the project $381 million, which was used to repay loans made by commercial banks during the period of the project's construction.

In addition, the amortization schedule for repayment of the project's loans was extended to take into account the effect upon the project of the lower cash flow resulting from the restructured electricity tariff. The initial principal repayment under the new amortization schedule was made on February 18, 2003. Dividend distributions from the project to shareholders are not anticipated to commence until 2006. As a condition to the making of the loans by the United States Export-Import Bank of the United States, all commercial disputes related to the project were settled without a material effect on EME. EME believes that it will ultimately recover its investment in the project.

EME's investment in the Paiton project increased to $514 million at December 31, 2002, from $492 million at December 31, 2001. The increase in the investment account resulted from EME's subsidiary recording its proportionate share of net income from Paiton Energy. EME's investment in the Paiton project will increase or decrease from earnings or losses from Paiton Energy and decrease by cash distributions. Assuming Paiton Energy remains profitable, EME expects the investment account to increase substantially during the next several years as earnings are expected to exceed cash distributions.

During 2002, PT Batu Hitam Perkasa (BHP), one of the other shareholders in Paiton Energy, reinstated a previously suspended arbitration to resolve disputes under the fuel supply agreement between BHP and Paiton Energy. The arbitration commenced in 1999 but had been stayed since that time to allow the parties to engage in settlement discussions related to a restructuring of the coal supply arrangements for the Paiton project. These discussions did not at the time lead to settlement, and BHP requested an arbitration tribunal to reinstate the original arbitration and to permit BHP to assert additional claims. In total, BHP's claims amounted to $250 million.

On December 19, 2002, Paiton Energy and BHP entered into an agreement in which all claims in the arbitration were settled and agreement was reached to dismiss the arbitration with no material effect upon Paiton Energy. Paiton Energy made the required payment to BHP under the terms of the settlement agreement and all claims have been dismissed.

Spent Nuclear Fuel

Under federal law, the U.S. Department of Energy (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. 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 0.1¢ per kWh of nuclear-generated electricity sold after April 6, 1983.

SCE, as operating agent, has primary responsibility for the interim storage of its spent nuclear fuel at San Onofre. The San Onofre Units 2 and 3 spent fuel pools currently contain San Onofre Unit 1 spent fuel in addition to spent fuel from Units 2 and 3. Current capability to store spent fuel in the Units 2 and 3 spent fuel pools is adequate through 2005. SCE plans to move the Unit 1 spent fuel to an interim spent fuel storage facility by the third quarter of 2003. The spent fuel pool storage capacity for Units 2 and 3 will then accommodate needs until 2007 for Unit 2 and 2008 for Unit 3. SCE expects to begin using an interim spent fuel storage facility for Units 2 and 3 spent fuel by early 2006. 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, expects to begin using an interim spent fuel storage facility in the first half of 2003.

Storm Lake

As of December 31, 2002, Edison Capital had an investment of approximately $82 million in Storm Lake Power, a project developed by Enron Wind, a subsidiary of Enron Corporation. As of December 31, 2002, Storm Lake had outstanding loans of approximately $69 million. Enron and its subsidiary provided certain guarantees related to the amount of power that would be generated from Storm Lake. The lenders have sent a notice to Storm Lake claiming that Enron's bankruptcy, among other things, is an event of default under the loan agreement. In the event of default, the lenders may exercise certain remedies, including acceleration of the loan balance, repossession and foreclosure of the project, which could result in the loss of some or all of Edison Capital's investment in Storm Lake. While expressly reserving their rights, the lenders have not taken any steps to exercise their remedies beyond issuing the notices of default. On behalf of Storm Lake, Edison Capital is also engaged in regular, ongoing discussions with the lenders in which Edison Capital expects to demonstrate to the lenders that Storm Lake's ability to meet its loan obligations is not impaired and that the noticed events of default can be worked out with the lenders. Edison Capital believes that Storm Lake will vigorously oppose any attempt by the lenders to exercise remedies that could result in a loss of Edison Capital's investment.

Note 11. Investments in Leveraged Leases, Partnerships and Unconsolidated Subsidiaries

Leveraged Leases

Edison Capital is the lessor in several leveraged-lease agreements with terms of 24 to 38 years. Each of Edison Capital's leveraged lease transactions was completed and accounted for in accordance with lease accounting standards. All operating, maintenance, insurance and decommissioning costs are the responsibility of the lessees. The acquisition cost of these facilities was $6.9 billion and $7.0 billion at December 31, 2002 and 2001, respectively.

The equity investment in these facilities is generally 20% of the cost to acquire the facilities. The balance of the acquisition costs was funded by nonrecourse debt secured by first liens on the leased property. The lenders do not have recourse to Edison Capital in the event of loan default.

The net income from leveraged leases is:

In millions Year ended December 31,	**2002**	2001	2000
Income from leveraged leases	**$ 105**	$ 154	$ 192
Recomputation due to tax rate change	**(99)**	—	—
Tax effect of pre-tax income:			
Current	**138**	246	311
Deferred	**(86)**	(307)	(388)
Total	**52**	(61)	(77)
Net income from leveraged leases	**$ 58**	$ 93	$ 115

The net investment in leveraged leases is:

In millions December 31,	**2002**	2001
Rentals receivable (net of principal and interest on nonrecourse debt)	**$ 3,496**	$ 3,555
Unearned income	**(1,260)**	(1,258)
Investment in leveraged leases	**2,236**	2,297
Estimated residual value	**42**	57
Deferred income taxes	**(2,044)**	(1,972)
Net investment in leveraged leases	**$ 234**	$ 382

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 projects and oil and gas investments and the underlying equity in the net assets was $272 million at December 31, 2002. The difference related to the energy projects is being amortized over the life of the energy projects; the difference related to the oil and gas investments is amortized on a unit-of-production basis over the life of the reserves for the oil and gas projects. Amortization stopped January 1, 2002 in accordance with a new accounting standard.

Summarized financial information of these investments is:

In millions	Year ended December 31,	2002	2001	2000
Revenue		**$ 1,523**	$ 3,380	$ 3,013
Expenses		**1,312**	2,847	2,464
Net income		**$ 211**	$ 533	$ 549

In millions	December 31,	2002	2001
Current assets		**$ 790**	$ 2,274
Other assets		**5,564**	10,059
Total assets		**$ 6,354**	$ 12,333
Current liabilities		**$ 1,205**	$ 1,971
Other liabilities		**3,759**	7,435
Equity		**1,390**	2,927
Total liabilities and equity		**$ 6,354**	**$ 12,333**

The undistributed earnings of investments accounted for by the equity method were $275 million in 2002 and $331 million in 2001.

Under a new accounting interpretation issued in January 2003, if an enterprise absorbs the majority of the VIE's expected losses or receives a majority of the VIE's expected residual returns, or both, it must consolidate the VIE. An enterprise that is required to consolidate the VIE is called the primary beneficiary. Additional disclosure requirements are also applicable when an enterprise holds a significant variable interest in a VIE, but is not the primary beneficiary. In addition, financial statements issued after January 31, 2003 must include certain disclosures if it is reasonably possible that an enterprise will consolidate or disclose information about a VIE when this interpretation is effective.

EME has concluded that it is the primary beneficiary of its Brooklyn Navy Yard project since it is at risk with respect to the majority of its losses and is entitled to receive the majority of its residual returns. Accordingly, EME will consolidate Brooklyn Navy Yard, effective July 1, 2003. EME expects the consolidation of this entity to increase total assets by approximately $365 million and total liabilities by approximately $445 million. EME expects to record a loss of up to $80 million as a cumulative change of accounting as a result of consolidating this variable interest entity. This loss is primarily due to cumulative losses allocated to the other 50% partner in excess of equity contributions recorded.

EME believes it is reasonably possible that certain partnership interests in energy projects are VIEs under this interpretation, as discussed below:

EME owns certain partnership interests in seven energy partnerships, which own a combined 3,098 MW of power plants. These partnerships generally sell the electricity under power purchase agreements that expire at various dates through 2039. The maximum exposure to loss from EME's interest in these entities is $1.1 billion at December 31, 2002. Of this amount, $541 million represents EME's investment in the 1,230 MW Paiton project and $307 million represents EME's investment in the 540 MW EcoEléctrica project.

EME owns a 50% interest in TM Star, which was formed for the limited purpose to sell natural gas to another affiliated project under a fuel supply agreement. TM Star has entered into fuel purchase contracts with unrelated third parties to meet a portion of the obligations under the fuel supply agreement. EME has guaranteed 50% of the obligation under the fuel supply agreement to March Point. The maximum loss is subject to changes in natural gas prices. Accordingly, the maximum exposure to loss cannot be determined.

Note 12. Business Segments

Edison International's reportable business segments include its electric utility segment (SCE), a nonutility power generation segment (EME) and a 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 that supplies electric energy to a 50,000 square-mile area of central, coastal and Southern California. SCE also produces electricity. EME is engaged in the 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 financial services with investments worldwide.

The accounting policies of the segments are the same as those described in Note 1.

A significant source of revenue from EME's sale of energy and capacity is derived from sales to Exelon Generation Company under power purchase agreements terminating in December 2004. Revenue from such sales was $1.1 billion for each of the years 2002, 2001 and 2000. The nonutility power generation segment is responsible for the goodwill reported on the consolidated balance sheets.

Edison International's business segment information is:

In millions	Electric Utility	Nonutility Power Generation	Financial Services	Corporate & Other(1)	Edison International
2002					
Operating revenue	$ 8,705	$ 2,750	$ 7	$ 26	$ 11,488
Depreciation, decommissioning and amortization	780	247	—	3	1,030
Interest and dividend income	262	18	(1)	8	287
Equity in income from partnerships and unconsolidated subsidiaries – net	—	283	(34)	—	249
Interest expense – net of amounts capitalized	584	452	36	211	1,283
Income tax (benefit) – continuing operations	642	38	(146)	(143)	391
Income (loss) from continuing operations	1,228	82	33	(208)	1,135
Net income (loss)	1,228(2)	25	33	(209)	1,077
Total assets	18,314	11,092	3,479	399	33,284
Additions to and acquisition of property and plant	1,046	554	1	(11)	1,590
2001					
Operating revenue	$ 8,120	$ 2,594	$ 202	$ 146	$ 11,062
Depreciation, decommissioning and amortization	681	273	17	2	973
Interest and dividend income	215	35	19	13	282
Equity in income from partnerships and unconsolidated subsidiaries – net	—	374	(31)	—	343
Interest expense – net of amounts capitalized	785	547	64	186	1,582
Income tax (benefit) – continuing operations	1,658	96	(24)	(83)	1,647
Income (loss) from continuing operations	2,386	113	84	(181)	2,402
Net income (loss)	2,386(2)	(1,121)	84	(314)	1,035
Total assets	22,453	10,730	3,736	(145)	36,774
Additions to and acquisition of property and plant	688	242	3	—	933
2000					
Operating revenue	$ 7,870	$ 2,294	$ 274	$ (14)	$ 10,424
Depreciation, decommissioning and amortization	1,473	282	28	1	1,784
Interest and dividend income	173	31	10	(5)	209
Equity in income from partnerships and unconsolidated subsidiaries – net	—	267	(20)	—	247
Interest expense – net of amounts capitalized	572	558	57	70	1,257
Income tax (benefit) – continuing operations	(1,022)	81	(10)	(68)	(1,019)
Income (loss) from continuing operations	(2,050)	101	135	(125)	(1,939)
Net income (loss)	(2,050)(2)	125	135	(153)	(1,943)
Total assets	15,966	15,017	3,713	404	35,100
Additions to and acquisition of property and plant	1,096	331	1	45	1,473

(1) Includes amounts from nonutility subsidiaries not significant as a reportable segment.
(2) Net income (loss) available for common stock.

The net income (loss) reported for nonutility power generation includes income (loss) from discontinued operations of $(57) million for 2002, $(1.2) billion for 2001 and $24 million for 2000. The net loss reported for corporate and other includes income (loss) from discontinued operations of $(1) million for 2002, $(133) million for 2002 and $(28) million for 2000.

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. A project in Australia sells its energy through a centralized power pool. A project in the United Kingdom sells its energy production by entering into physical bilateral contracts with various counterparties. Other electric power generated overseas is sold under short- and long-term contracts to electricity companies, electricity buying groups or electric utilities located in the country where the power is generated.

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

In millions Year ended December 31,	2002	2001	2000
Revenue			
United States	**$ 10,331**	$ 10,141	$ 9,673
Foreign countries:			
United Kingdom	**317**	324	443
Australia	**204**	166	174
New Zealand	**493**	294	—
Netherlands	**(24)**	—	—
South Africa	**(16)**	—	—
Switzerland	**56**	—	—
Other	**127**	137	134
Total	**$ 11,488**	$ 11,062	$10,424

In millions December 31,	2002	2001
Assets		
United States	**$ 25,420**	$ 31,532
Foreign countries:		
United Kingdom(1)	**1,680**	1,675
Australia	**1,565**	1,152
New Zealand	**1,738**	1,331
Netherlands	**556**	—
South Africa	**646**	—
Switzerland	**483**	—
Other	**1,196**	1,084
Total	**$ 33,284**	$ 36,774

(1) Includes assets of discontinued operations.

Note 13. Acquisitions and Dispositions

On March 3, 2003, Contact Energy Ltd. completed a transaction with NGC Holdings Ltd. to acquire the Taranaki combined cycle power station and related interests for NZ$500 million ($280 million). The NZ$500 million purchase price was financed with bridge loan facilities. Contact Energy intends to refinance these facilities with the issuance of long-term senior debt. The Taranaki station is a 357 MW combined cycle, natural gas-fired plant located near Stratford, New Zealand.

During the second quarter of 2001, EME completed the purchase of additional shares of Contact Energy Ltd. for NZ$152 million, increasing its ownership interest from 43% to 51%. EME acquired 40% of the shares of Contact Energy during 1999 and increased its share of ownership to 43% during 2000. Accordingly, EME began accounting for Contact Energy on a consolidated basis effective June 1, 2001, upon acquisition of a controlling interest. Prior to June 1, 2001, EME used the equity method of accounting for Contact Energy. To finance the purchase of the additional shares in 2001, EME obtained a NZ$135 million, 364-day bridge loan from an investment bank under a credit facility, which was syndicated by the bank. In addition to other security arrangements, a security interest over all Contact Energy shares held has been provided as collateral. From June 2001 to October 2001, EME issued through one of its subsidiaries new preferred securities. The proceeds were used to repay borrowings outstanding under a credit facility and to repay the bridge loan.

In February 2001, EME completed the acquisition of a 50% interest in CBK Power Co. Ltd. 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 includes equity commitments of $117 million (EME's share is approximately $59 million) and debt financing, which is in place for the remainder of the cost of this project. As of December 31, 2002, EME has made equity contributions of $21 million. For a more detailed discussion of the commitment to contribute project equity, see "Other Commitments" in Note 9.

In September 2000, EME acquired the trading operations of Citizens Power LLC and a minority interest in certain structured transaction investments. The purchase price of $45 million (funded from existing cash) was based on the sum of the fair market value of the trading portfolio and the structured transaction investments, plus $25 million.

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. At December 31, 2002, 303 MW had been commissioned and are operational The purchase price of the acquisition was $44 million with equity contribution obligations of up to $16 million, depending on the number of projects that are ultimately developed. By December 31, 2001, the entire equity contribution was funded.

During 2002, EME completed the sales of its 50% interests in the Commonwealth Atlantic and James River projects and its 30% interest in the Harbor project. Proceeds received from the sales were $44 million. During 2001, EME recorded asset impairment charges of $32 million related to these projects based on the expected sales proceeds. No gain or loss was recorded from the sale of EME's interests in these projects during 2002.

During 2001, EME completed the sales of its interests in the Nevada Sun-Peak project (50%), Saguaro project (50%) and Hopewell project (25%) for a total gain on sale of $45 million ($24 million after tax). In addition, EME entered into agreements, subject to obtaining consents from third parties and other conditions, for the sale of its interests in the Commonwealth Atlantic, Gordonsville, EcoEléctrica, Harbor and James River projects. During 2001, EME recorded asset impairment charges of $34 million related to these projects based on the expected sales proceeds. The sales of EME's interests in the EcoEléctrica and Gordonsville projects have not closed, and in each case the buyer has terminated the sale agreement.

Also, during 2001, EME sold a 50% interest in its Sunrise project to Texaco for $84 million (50% of the project costs, prior to commercial operation). In late 2000, EME had purchased from Texaco all rights, title and interest in the Sunrise project; Texaco had an option to repurchase, at cost, a 50% interest in the project.

In December 2001, EME completed the sale of the Ferrybridge and Fiddler's Ferry coal-fired power plants located in the United Kingdom. See additional discussion in Note 14.

In 2001, Edison Capital syndicated its interests in several affordable housing projects for $169 million and recorded fee and syndication income of $40 million (after tax) resulting from the syndication.

Note 14. Discontinued Operations

On December 19, 2002, the lenders to the Lakeland project accelerated the debt owing under the bank agreement that governs the project's indebtedness, and on December 20, 2002, the Lakeland project lenders appointed an administrative receiver over the assets of Lakeland Power Ltd. The appointment of the administrative receiver results in the treatment of Lakeland power plant as an asset held for sale under an accounting standard related to the impairment or disposal of long-lived assets. Due to EME's loss of control arising from the appointment of the administrative receiver, EME no longer consolidates the activities of Lakeland Power Ltd. The loss from operations of Lakeland in 2002 includes an impairment charge of $92 million ($77 million after tax) and a provision for bad debts of $1 million, after tax, arising from the write-down of the Lakeland power plant and related claims under the power sales agreement (an asset group according to an impairment standard) to their fair market value. The fair value of the asset group was determined based on discounted cash flows and estimated recovery under related claims under the power sales agreement.

On December 21, 2001, EME completed the sale of Fiddler's Ferry and Ferrybridge coal stations located in the United Kingdom to two wholly owned subsidiaries of American Electric Power. The net proceeds from the sale (£643 million) were used to repay borrowings outstanding under the existing debt facility related to the acquisition of the plants. In addition, the buyers acquired other assets and assumed specific liabilities associated with the plants. EME recorded a charge of $1.9 billion ($1.1 billion after tax) related to the loss on sale. The $1.9 billion charge includes the asset impairment charge recorded in third quarter 2001 to reduce the carrying value of the assets held for sale to reflect estimated fair value less the cost to sell and related currency adjustments. EME had acquired the plants in 1999 for approximately $2.0 billion (£1.3 billion).

In August 2001, Edison Enterprises, a wholly owned subsidiary of Edison International, sold a subsidiary principally engaged in the business of providing residential security services and residential electrical warranty repair services. In October 2001, Edison Enterprises completed the sale of substantially all of its assets of another subsidiary (engaged in the business of commercial energy management) to the subsidiary's current management. As a result, Edison International recorded a charge of $127 million (after tax) in 2001 related to the loss on sale. The impairment charges recorded in 2001 to reduce the carrying value of these investments held for sale to reflect the estimated fair value less cost to sell are included in the $127 million charge.

In 2002, the results of the Lakeland project are reflected as discontinued operations in the consolidated financial statements in accordance with an accounting standard related to the impairment and disposal of long-lived assets. Due to immateriality, the results of the Lakeland project in 2001 and 2000 have not been restated and are reflected as part of continuing operations. For all years presented, the results of the Fiddler's Ferry and Ferrybridge coal stations and Edison Enterprises subsidiaries sold during 2001 have been reflected as discontinued operations in the consolidated financial statements in accordance with an accounting standard related to the impairment and disposal of long-lived assets. The consolidated financial statements have been restated to conform to the discontinued operations presentation for all years presented. Revenue from discontinued operations was $74 million in 2002, $748 million in 2001 and $1.0 billion in 2000. The before-tax losses of the discontinued operations were $74 million in 2002, $2.2 billion in 2001 and $34 million in 2000.

The carrying value of assets and liabilities of discontinued operations is:

In millions December 31,	**2002**	2001
Assets		
Cash and equivalents	**$ —**	$ 63
Receivables – net	**1**	1
Other	**3**	90
Total current assets	**4**	154
Nonutility property – net	**—**	—
Other noncurrent assets	**57**	51
Total assets	**$ 61**	$ 205
Liabilities		
Accounts payable and accrued liabilities	**$ 23**	$ 59
Current maturities of long-term obligations	**—**	—
Short-term debt and other	**—**	5
Total current liabilities	**23**	64
Noncurrent liabilities	**49**	7
Total liabilities	**$ 72**	$ 71

Note 15. Subsequent Event

An indirect subsidiary of EME, First Hydro Finance plc, is the borrower of £400 million ($644 million at December 31, 2002) of guaranteed secured bonds due 2021. The ability of EME's subsidiary to make payments of interest on the First Hydro bonds is dependent on revenue generated by the First Hydro plant, which depends on market conditions for electric energy and ancillary services. These market conditions are beyond EME's control. The financial covenants included in the bond financing of First Hydro require EME's subsidiary to maintain a minimum interest coverage ratio for each trailing 12-month period as of June 30 and December 31 of each year. EME's subsidiary was in compliance with this ratio for the 12 months ended December 31, 2002. Compliance with this ratio depends on market conditions for electric energy and ancillary services. There is no assurance that these requirements will be met and, if not met, will be waived by the holders of First Hydro's bonds. The bond financing documents stipulate that a breach of a financial covenant constitutes an immediate event of default and, if the event of default is not waived or cured, the holders of the First Hydro bonds are entitled to enforce their security over First Hydro's assets, including its power plants.

On March 14, 2003, First Hydro Finance plc received a letter from the trustee for the First Hydro bonds, requesting that First Hydro Finance engage in a process to determine whether an early redemption option in favor of the bondholders has been triggered under the terms of the First Hydro bonds. This letter states that, given requests made of the trustee by a group of First Hydro bondholders, the trustee needs to satisfy itself whether the termination of the pool system in the United Kingdom (replaced with the new electricity trading arrangements, referred to as NETA), was materially prejudicial to the interests of the bondholders. If this were the case, it could provide the First Hydro bondholders with an early redemption option. In this regard, on August 29, 2000, First Hydro Finance notified the trustee that the enactment of the Utilities Act of 2000, which laid the foundation for NETA, would result, after its implementation, in a so-called restructuring event under the terms of the First Hydro bonds. However, First Hydro Finance did not believe then, nor does it believe now, that this event was materially prejudicial to the First Hydro bondholders. Since NETA implementation, First Hydro Finance has continued to meet all of its debt service obligations and financial covenants under the bond documentation, including the required interest coverage ratio. Until its receipt of the trustee's March 14, 2003 letter, First Hydro Finance had not received a response from the trustee to its August 29, 2000 notice. First Hydro Finance will vigorously dispute any attempt to have the early redemption option deemed applicable due to NETA implementation.

Neither the August 2000 notice provided to the trustee nor the March 14, 2003 letter from the trustee constitutes an event of default under the terms of the First Hydro bonds and there is no recourse to EME for the obligations of First Hydro Finance in respect of the First Hydro bonds. However, if the bondholders were entitled to an early redemption option, First Hydro Finance would be obligated to purchase all First Hydro bonds put to it by bondholders at par plus an early redemption premium. If all bondholders opted for the early redemption option, it is unlikely that First Hydro Finance would have sufficient financial resources to purchase the bonds. There is no assurance that First Hydro Finance would be able to obtain additional financing to fund the purchase of the First Hydro bonds. Therefore, an exercise of the early redemption option by the bondholders could lead to administration proceedings as to First Hydro Finance in the United Kingdom, which is similar to Chapter 11 bankruptcy proceedings in the United States. If these events occur, it would have a material adverse effect upon First Hydro Finance and could have a material adverse effect upon EME and Edison International.

	2002				
In millions, except per share amounts	Total	Fourth	Third	Second	First
Operating revenue	$ 11,488	$ 2,469	$ 3,707	$ 2,824	$ 2,488
Operating income	2,372	156	703	1,204	309
Income (loss) from continuing operations	1,135	56	345	655	79
Income (loss) from discontinued operations – net	(58)	(80)	7	10	5
Net income (loss)	1,077	(24)	352	665	84
Basic earnings (loss) per share:					
Continuing operations	3.49	0.18	1.06	2.01	0.24
Discontinued operations	(0.18)	(0.25)	0.02	0.03	0.02
Total	3.31	(0.07)	1.08	2.04	0.26
Diluted earnings (loss) per share:					
Continuing operations	3.46	0.17	1.05	1.99	0.24
Discontinued operations	(0.18)	(0.24)	0.02	0.03	0.02
Total	3.28	(0.07)	1.07	2.02	0.26
Dividends declared per share	—	—	—	—	—
Common stock prices:					
High	19.60	12.25	17.24	19.60	17.56
Low	7.80	7.80	8.80	16.26	14.82
Close	11.85	11.85	10.00	17.00	16.75

	2001				
In millions, except per share amounts	Total	Fourth	Third	Second	First
Operating revenue	$ 11,062	$ 2,870	$ 3,750	$ 2,331	$ 2,111
Operating income	5,082	3,898	1,642	339	(797)
Income (loss) from continuing operations	2,402	2,172	801	59	(630)
Income (loss) from discontinued operations – net	(1,367)	(5)	(1,214)	(161)	13
Net income (loss)	1,035	2,167	(413)	(102)	(617)
Basic earnings (loss) per share:					
Continuing operations	7.37	6.66	2.46	0.18	(1.93)
Discontinued operations	(4.19)	(0.01)	(3.73)	(0.49)	0.04
Total	3.18	6.65	(1.27)	(0.31)	(1.89)
Diluted earnings (loss) per share:					
Continuing operations	7.36	6.66	2.46	0.18	(1.93)
Discontinued operations	(4.19)	(0.01)	(3.73)	(0.49)	0.04
Total	3.17	6.65	(1.27)	(0.31)	(1.89)
Dividends declared per share	—	—	—	—	—
Common stock prices:					
High	16.12	16.12	15.08	12.98	15.8125
Low	6.25	13.80	10.46	7.51	6.25
Close	15.10	15.10	13.16	11.15	12.64

The amounts reported above are different from those previously reported because of the reclassification discussed in "Basis of Presentation" in Note 1. In addition, the Lakeland asset impairment in 2002 and the sales of generating plants and other assets during 2001 are reported as discontinued operations in accordance with an accounting standard issued in October 2001. Edison International adopted the standard in fourth quarter 2001; prior periods have been restated to reflect continuing operations, unless noted otherwise.

Selected Financial and Operating Data: 1998 – 2002 — Edison International

Dollars in millions, except per-share amounts	**2002**	2001	2000	1999	1998
Edison International and Subsidiaries					
Operating revenue	**$ 11,488**	$ 11,062	$ 10,424	$ 8,932	$ 8,671
Operating expenses	**$ 9,116**	$ 5,980	$ 12,499	$ 7,359	$ 7,076
Income (loss) from continuing operations	**$ 1,135**	$ 2,402	$ (1,939)	$ 681	$ 668
Net income (loss)	**$ 1,077**	$ 1,035	$ (1,943)	$ 623	$ 668
Weighted-average shares of common stock outstanding (in millions)	**326**	326	333	348	359
Basic earnings per share:					
Continuing operations	**$ 3.49**	$ 7.37	$ (5.83)	$ 96	$ 1.86
Discontinued operations	**$ (0.18)**	$ (4.19)	$ (0.01)	$ (0.17)	—
Total	**$ 3.31**	$ 3.18	$ (5.84)	$ 1.79	$ 1.86
Diluted earnings per share	**$ 3.28**	$ 3.17	$ (5.84)	$ 1.79	$ 1.84
Dividends declared per share	**—**	—	$ 0.84	$ 1.08	$ 1.04
Book value per share at year-end	**$ 13.62**	$ 10.04	$ 7.43	$ 15.01	$ 14.55
Market value per share at year-end	**$ 11.85**	$ 15.10	$ 15.625	$ 26.187	$ 27.875
Rate of return on common equity	**27.0%**	58.0%	(41.0)%	12.2%	12.8%
Price/earnings ratio	**3.6**	4.7	(2.7)	14.6	15.0
Ratio of earnings to fixed charges	**2.08**	3.21	*	1.99	2.33
Assets	**$ 33,284**	$ 36,774	$ 35,100	$ 36,229	$ 24,698
Long-term debt	**$ 11,557**	$ 12,674	$ 12,150	$ 13,391	$ 8,008
Common shareholders' equity	**$ 4,436**	$ 3,272	$ 2,420	$ 5,211	$ 5,099
Preferred stock subject to mandatory redemption	**$ 147**	$ 151	$ 256	$ 256	$ 256
Company-obligated mandatorily redeemable securities of subsidiaries holding solely parent company debentures	**$ 951**	$ 949	$ 949	$ 948	$ 150
Retained earnings	**$ 2,711**	$ 1,634	$ 599	$ 3,079	$ 2,906
Southern California Edison Company					
Operating revenue	**$ 8,706**	$ 8,126	$ 7,870	$ 7,548	$ 7,500
Net income (loss) available for common stock	**$ 1,228**	$ 2,386	$ (2,050)	$ 484	$ 490
Basic earnings (loss) per Edison International common share	**$ 3.77**	$ 7.32	$ (6.16)	$ 1.39	$ 1.37
Rate of return on common equity	**31.8%**	311.0%	(67.6)%	15.2%	13.3%
Peak demand in megawatts (MW)	**18,821**	17,890	19,757	19,122	19,935
Generation capacity at peak (MW)	**9,767**	9,802	9,886	10,431	10,546
Kilowatt-hour deliveries (in millions)	**79,693**	78,524	84,430	78,602	76,595
Customers (in millions)	**4.53**	4.47	4.42	4.36	4.27
Full-time employees	**12,113**	11,663	12,593	13,040	13,177
Edison Mission Energy					
Revenue	**$ 2,750**	$ 2,594	$ 2,294	$ 1,083	$ 705
Income from continuing operations	**$ 76**	$ 113	$ 101	$ 109	$ 132
Net income (loss)	**$ 18**	$ (1,121)	$ 125	$ 130	$ 132
Assets	**$ 11,090**	$ 10,730	$ 15,017	$ 15,534	$ 5,158
Rate of return on common equity	**1.5%**	(46.9)%	4.3%	8.1%	14.8%
Ownership in operating projects (MW)	**18,688**	19,019	22,759	22,037	5,153
Full-time employees	**2,662**	3,021	3,391	3,245	1,180
Edison Capital					
Revenue	**$ 7**	$ 202	$ 274	$ 282	$ 235
Net income	**$ 33**	$ 84	$ 135	$ 129	$ 105
Assets	**$ 3,479**	$ 3,736	$ 3,713	$ 2,712	$ 2,276
Rate of return on common equity	**4.2%**	11.9%	22.9%	27.0%	30.2%
Full-time employees	**61**	66	119	115	85

* less than 1.00

During 2002, EME recorded an impairment charge related to its Lakeland plant and during 2001, EME sold its generating plants located in the United Kingdom and Edison Enterprises sold the majority of its assets. Amounts presented in this table have been restated to reflect continuing operations unless stated otherwise. See Note 14, Discontinued Operations, for further discussion.

Board of Directors*

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Chairman of the Board,
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1 Audit Committee
2 Compensation and Executive Personnel Committee
3 Executive Committee
4 Finance Committee
5 Nominating/Corporate Governance Committee

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

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And General Counsel

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Chief Information Officer

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Vice President and
General Auditor

Jo Ann Goddard
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Investor Relations

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Vice President and Controller

Barbara J. Parsky
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Corporate Communications

Beverly P. Ryder
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Community Involvement,
And Secretary

Anthony L. Smith
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Vice President, Power Production

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Vice President and Controller

Dwight E. Nunn
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Pedro J. Pizarro
Vice President,
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Development

Frank J. Quevedo
Vice President,
Equal Opportunity

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Anthony L. Smith
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Joseph J. Wambold
Vice President,
Nuclear Generation

Beverly P. Ryder
Corporate Secretary

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Executive Vice President and
General Manager, Asia Pacific

Ronald L. Litzinger
Senior Vice President and
Chief Technical Officer

S. Daniel Melita
Senior Vice President and
General Manager, Europe

Georgia R. Nelson
Senior Vice President and
General Manager, Americas;
President, Midwest Generation

Kevin M. Smith
Senior Vice President,
Chief Financial Officer and
Treasurer

Raymond W. Vickers
Senior Vice President and
General Counsel

1 Effective April 1, 2003, Formerly Vice President, Engineering and Technical Services
2 Retiring April 1, 2003

EDISON CAPITAL

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Chairman of the Board

Thomas R. McDaniel
Chief Executive Officer

Ashraf T. Dajani
President and Chief Operating Officer

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

Phillip B. Dandridge
Vice President and Chief Financial Officer

Shareholder Information

The annual meeting of shareholders will be held on Thursday, May 15, at 10:00 a.m., at the Hyatt Regency Long Beach, 200 South Pine Avenue, Long Beach, California.

Corporate Governance Practices

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

Stock 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 listed preferred stocks 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% and 7.23% series of the $100 cumulative preferred stock are not listed; however, the 7.23% series is 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., which maintains shareholder records, 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 7:00 a.m. and 7:00 p.m. (Central Time), Monday through Friday, to speak with a representative (or to use the interactive voice response unit 24 hours a day, seven days a week) regarding:

- stock transfer and name-change requirements;
- address changes, including dividend addresses;
- electronic deposit of dividends;
- taxpayer identification number submission or changes;
- duplicate 1099 forms 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.
Shareholder Services Department
161 North Concord Exchange Street
South St. Paul, MN 55075-1139

Fax
(651) 450-4033

Email
stocktransfer@wellsfargo.com

Web Address
www.edisoninvestor.com

On line account information
www.shareowneronline.com

Dividend Reinvestment and Electronic Transfer

A prospectus and enrollment forms for Edison International's Common Stock Dividend Reinvestment and Stock Purchase Plan are available from Wells Fargo Shareholder Services upon request.

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2244 Walnut Grove Avenue, Rosemead, California 91770
626.302.1212
www.edison.com