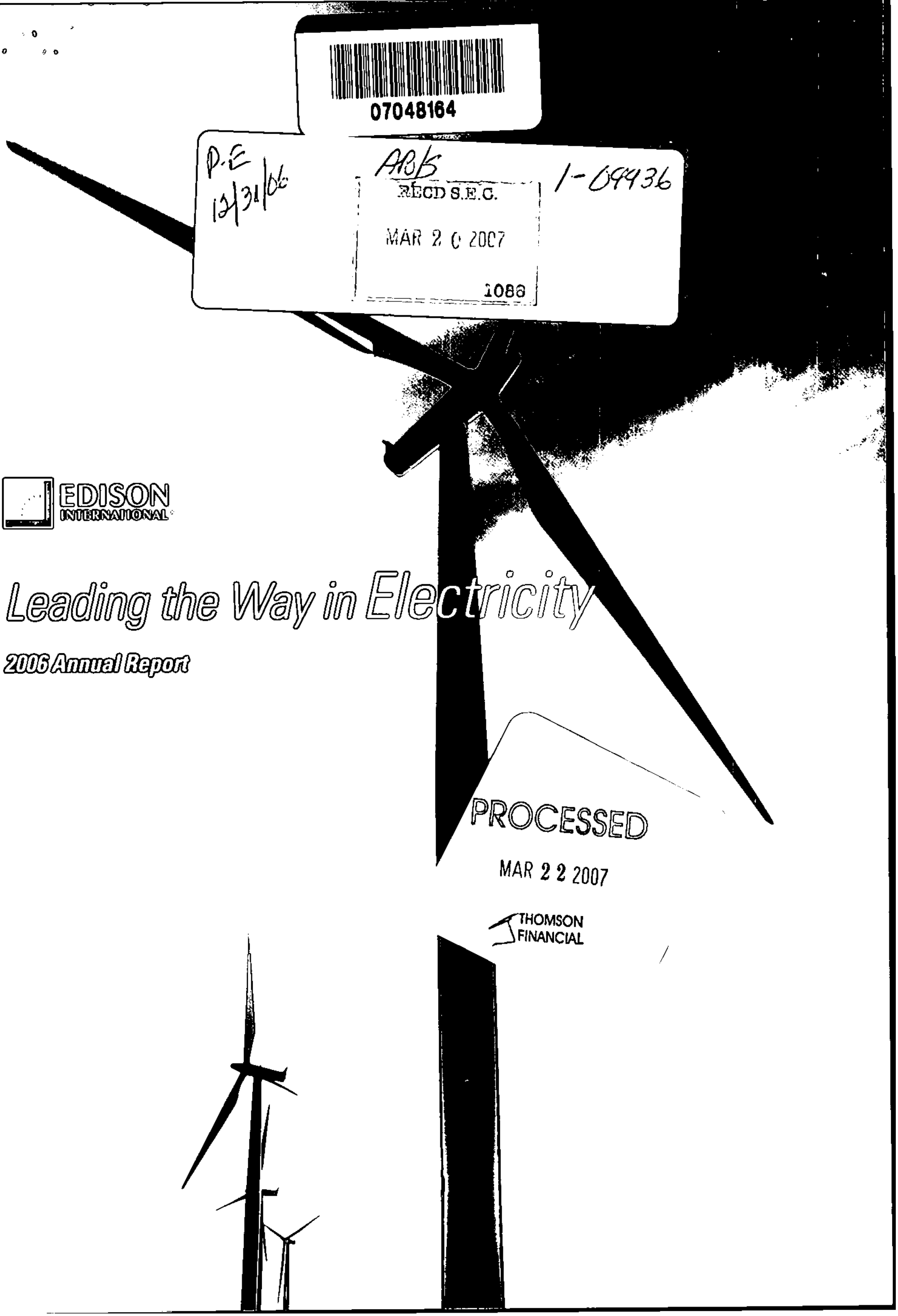


EDISON
INTERNATIONAL

Leading the Way in Electricity

2006 Annual Report

Our Vision

Leading the Way in Electricity

Our Values

- *Integrity*
- *Excellence*
- *Respect*
- *Continuous Improvement*
- *Teamwork*

Our Shared Enterprise

- Together we provide an indispensable service that powers society.
- We are a single enterprise that is stronger than the sum of its parts.

Our Operating Priorities

- *We operate safely*
- *We meet customer needs*
- *We value diversity*
- *We build productive partnerships*
- *We protect the environment*
- *We learn from experience and improve*
- *We grow the value of our business*

Dear Fellow Shareholders:

These are exciting times for the people of Edison International. We are significantly outperforming the five-year strategic plan announced in October 2004. As a result we now have a stronger foundation to achieve large-scale growth over the next five years.

John Bryson

Our strategic plan is to serve electricity markets building on what we have done in the past and know well how to do. As described in previous annual reports, it is based on the company's large potential for organic growth. Our performance in 2006 added to, and made clearer, that potential.

In the 2004 plan we forecast five-year annual growth in earning assets at Southern California Edison of 8 percent, near the top of regulated U.S. utilities. That was based on the considerable capital investment required to meet reliability and environmental objectives in SCE's rapidly growing service territory. Now, as a result of decisions and accomplishments over the last two years, we are increasing our growth estimate for SCE's earning assets to 12 percent or more, compounded annually, from 2007 through 2011. That assumes we receive the necessary regulatory approvals for proposed capital investments, which we believe to be consistent with state and federal policy. We know of no major U.S. utility with comparable challenges and opportunities for growth.

At Edison Mission Group, our competitive power generation subsidiary, the 2004 plan targeted substantial earnings growth, principally through paying down debt, reducing costs and improving operational efficiencies following the sale of our large international power generation portfolio. It anticipated relatively modest growth from new generation investments, primarily in wind energy. EMG has exceeded those earnings targets and is today a substantially stronger business. In each of the past two years EMG has generated cash as measured by EBITDA of about $1 billion. (EBITDA is the principal financial metric used by the financial community in assessing the relative cash-generation power of companies). The $2 billion total exceeded our 2004 projections by more than a half-billion dollars. The resulting financial strength will allow us to undertake larger and more diverse growth initiatives.

Overall, Edison International's financial results in 2006 were strong. Consolidated earnings set a record again in 2006, growing almost 4 percent to reach approximately $1.2 billion, or $3.58 per share. Assets increased to more than $36 billion. In December, the dividend was increased 7.4 percent to $1.16 per share. Total shareholder return was 7 percent. Although positive, that was below industry averages for 2006, as our stock price appreciation decelerated relative to the industry-leading returns of the past three- and five-year periods.

Strong Foundations for Growth at SCE

The substantial increase in SCE's growth outlook is attributable primarily to four factors:

The first is the need for sustained investment in Southern California's electricity infrastructure to maintain and strengthen reliability and keep pace with the region's rapid economic growth. The California Public Utilities Commission recognized and supported this need through authorization last May of approximately $5 billion of new capital investment for the years 2006 through 2008. Then Edison employees got the job done, completing in the past year a record $1.7 billion of the approved capital investments.

Second, we are addressing California's need for adequate electricity supply. We are further strengthening SCE's base load capacity through continued favorable progress on the replacement of steam generators at our San Onofre nuclear plant, which will help to ensure this important facility's operation well into the future. And more immediately: SCE's system is prone to large spikes in demand on the hottest days of the year. This peak demand is rising at a faster rate than average demand on the system. During the heat wave California experienced in July 2006, peak demand in the SCE service territory reached a new record of 22,889 megawatts, a 4.4 percent increase over 2005 and 10.2 percent higher than in 2004. This made clear the need for additional generation in the form of quick-start peaker plants, which can come on-line within minutes to provide emergency reserves. Governor Schwarzenegger and the CPUC responded with an order that SCE construct five such peaker plants targeted to be in service by August 2007.

Third, we continue to make progress in the construction and always-difficult permitting for a $4 billion expansion of our transmission system. We are expanding the system to the southwest, the north, and within our service territory and estimate completion of the current plan by about 2013. Particularly significant is our Tehachapi Renewable Transmission Project, a $1.7 billion investment that will make possible the development over the next several years of new wind farms in remote areas of eastern Kern County, California. It is the nation's first transmission project built primarily to enable development of renewable energy. When complete, Tehachapi could deliver 4,500 megawatts of wind energy, enough to power three million homes.

Fourth is our projected installation of an estimated five million advanced electricity meters over the next six years. In 2006 our work to develop the next generation of "smart" meters set the industry standard for advanced technology, cost effectiveness, breadth of features and benefits, and forward adaptability. Our collaborative approach with meter manufacturers has been so successful that in August we accelerated our timeline for installation by one year. We expect to invest approximately $1.2 billion from 2007 through full system-wide deployment in 2012, installing meters with the largest array of customer-service features offered by any U.S. utility.

In sum, with continued regulatory support, SCE has the potential to achieve industry-leading growth over the next five years.

Pursuing Diversified Growth at EMG

At EMG our growth initiatives progressed in three principal areas during 2006:

First, we substantially increased our prospects in the growing area of wind-energy generation. EMG placed five new wind projects comprising 342 megawatts into construction during 2006. Of greater significance, we have secured exclusive negotiation rights through joint development agreements on approximately 2,600 megawatts of wind-development projects in thirteen states. Not all of these will meet our investment criteria or result in operating wind farms, but the pipeline is promising.

Across the U.S., public demand for renewable energy – as well as state and federal support for its development – continues to grow. More than 20 states have now established goals for generation from renewable sources, with many more actively considering such standards. For EMG, wind projects offer the opportunity to help meet the demand by leveraging our experience and expertise in this area. They also diversify our generation portfolio, provide favorable cash flows from tax credits, and increase the percentage of our power contracted for in long-term agreements.

Second, we advanced the environmentally significant Carson Hydrogen Project. Together with our partner BP, we are developing a hydrogen-fueled power plant that would be the first of its kind. If successful, we will employ cutting-edge technology to generate between 400 and 450 megawatts of electricity in the heart of the Los Angeles basin, where new electricity sources are needed, with carbon emissions at a fraction of traditional power generation methods. In 2006 we won a $90 million federal tax credit for the project in a competitive process through the U.S. Department of Energy. The target operating date for the Carson plant is 2012-2013. Much remains to be done before we can commit finally to the large capital investment this exciting project will require.

Lastly, as part of a broader environmental agreement discussed in more detail below, Illinois Governor Blagojevich and his administration committed to work with us on commercially reasonable terms for the development of up to 400 megawatts of wind energy projects and one or more clean coal projects in the state. Work is underway to turn that commitment into the necessary foundation for investments.

Looking ahead, our diversified growth plan at EMG will include the development of new generation facilities, including renewable, natural gas-fired, and clean coal projects.

Responding to Environmental Concerns

Environmental considerations sharply intensified in 2006 as a driver of current costs and future prospects in the electricity industry. These concerns will continue to impact our business significantly in 2007 and beyond. Coal-fired power plants in particular will be challenged by broader goals to reduce emissions and address concerns about climate change.

At the end of 2006, EMG reached a significant long-term environmental agreement with the Illinois Environmental Protection Agency to further reduce emissions of mercury, sulfur dioxide and nitrogen oxide from Midwest Generation's fleet of coal-fired plants. The settlement, subject to state regulatory approval, defines a path to meet environmental objectives for these plants through 2018. It provides more certainty about future regulations and emissions allowances, allows us to phase in pollution-control projects over a reasonable time frame, and offers an important degree of flexibility in determining which plants warrant the substantial environmental retrofit investments which will be required to allow them to continue operation in the future.

There will be more environmental challenges. Greenhouse gas legislation has already been enacted in California. Federal legislation within the next few years is both probable and desirable. We support a comprehensive federal approach with consistent rules and reasonable time lines to allow new technology to develop, and one that minimizes reasonably avoidable economic disruption. We plan to be an active participant in the debate on this issue.

The key to reducing emissions in the next decade lies in a substantial increase in generation from renewable sources, expanded energy efficiency efforts, and the development and commercialization of new technologies.

SCE has since the 1980s led the nation in the use of generation from renewable sources. We now purchase more than one-sixth of the renewable electricity produced for retail sale in the U.S.

We lead the nation's utilities in helping our customers conserve electricity. From 1992 through 2005, SCE programs enabled our residential, commercial and industrial customers to avoid nearly nine million megawatt-hours of electricity usage – more than any other U.S. utility.

In electric transportation we have also taken a leadership position. SCE already operates the largest private fleet of electric vehicles in the U.S., reducing greenhouse gas emissions by 7,200 tons since starting the program in the early 1990s. Initiatives now underway include work with corporate and public-sector partners to develop the next generation of plug-in hybrid utility bucket trucks. We expect to receive delivery of the nation's first prototype by the end of 2007. Also this year construction will be complete on a hydrogen refueling station at our corporate headquarters in Rosemead; and shortly thereafter we plan to begin evaluation of a small test fleet of fuel-cell vehicles from several major automakers.

Developing Our People and Culture

Initiatives to enhance a company's culture can sound vague and of uncertain worth. Yet one need only look at Edison International's recent past to see the power of a strong corporate culture in action.

First at SCE during the California power crisis of 2000-2001, and then at EMG as the U.S. independent power industry substantially collapsed, our employees had to fight their way through very difficult challenges. The character they displayed made all the difference in protecting our company, its customers and shareholders.

In 2006, we evaluated the cultural values and behaviors that if consistently practiced would enhance our ability to seize the opportunities we see on the horizon. Executing our business strategy requires a commitment by our employees to continuous improvement, so that we can capture the value inherent in our existing businesses. Unlocking the full potential of our employees requires yet stronger emphasis on teamwork and working together as one company, consistent with all applicable regulatory rules.

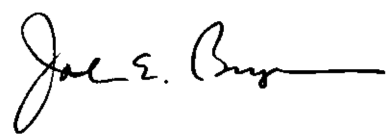
As a result of this analysis, we amended our corporate values for only the second time in the company's 120-year history. We reaffirmed our long-established values of excellence, integrity and respect. We added the values of "continuous improvement" and "teamwork." We then went deeper by defining the business behaviors associated with each value. This allows all of us to understand clearly how our corporate values can be lived through daily work practices.

With industry leadership on issues from renewable energy to advanced metering to electric vehicles, and with the potential for industry-leading growth over the next several years, our senior team in 2006 was inspired to adopt an apt new statement of company vision: *Leading the Way in Electricity*. That is a confident reflection of our company's proud past and our aspirations for the future.

Achieving our vision will require the full engagement of each Edison International employee. That won't be easy, but the challenges associated with leading the way, and consistently striving to improve, are more rewarding and simply more fun than many of the challenges met and overcome by Edison International employees in recent years.

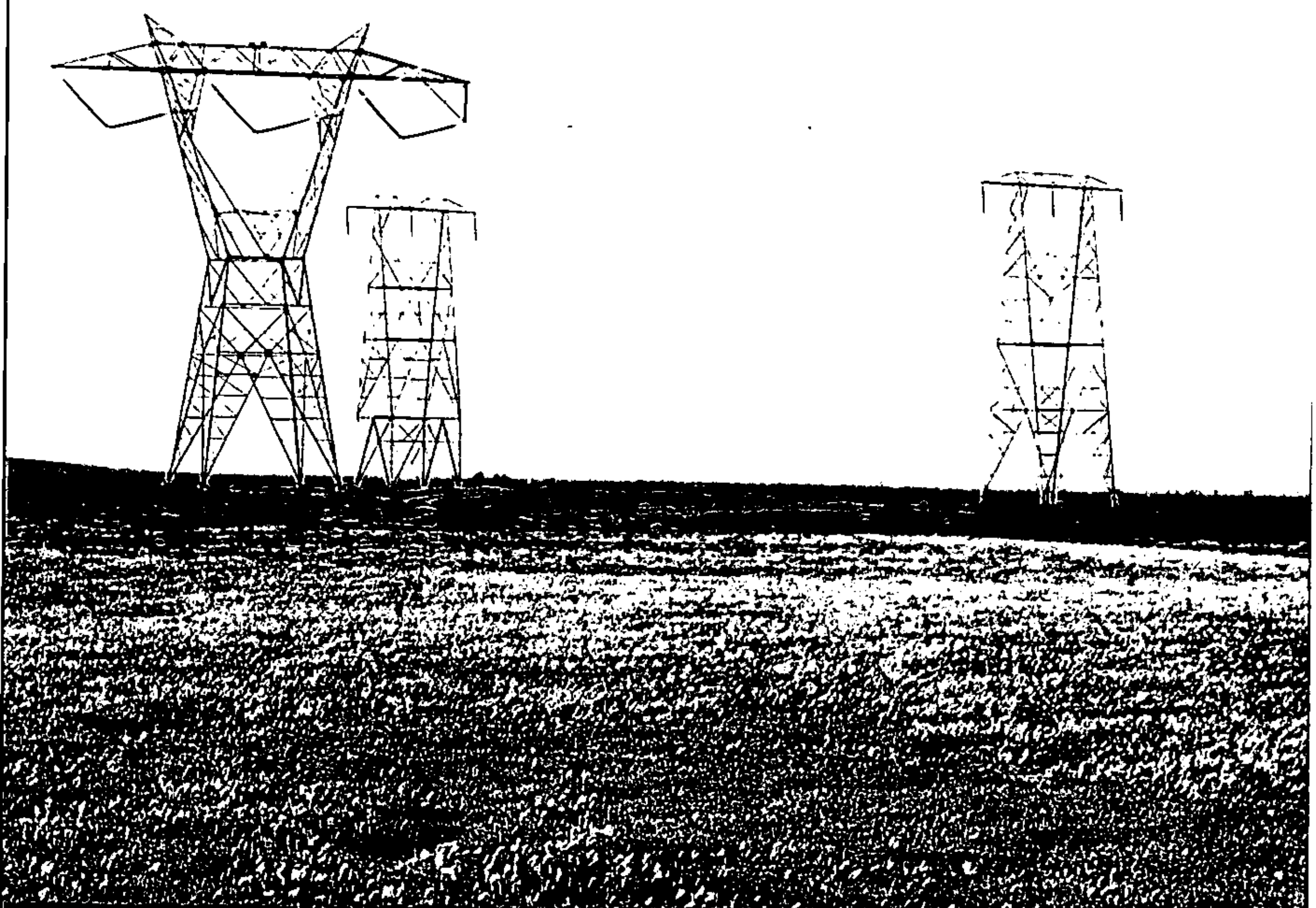
Thank you to all employees whose achievements and commitment to our values in 2006 made us a stronger business. And thank you, our shareholders, for your continued support.

Sincerely,



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

March 1, 2007



Southern California Edison plans to invest $4 billion over the next several years to expand the state's transmission system and access new sources of renewable energy. We're particularly proud of our Tehachapi Renewable Transmission Project, which addresses one of the largest barriers to the development of new renewable energy:

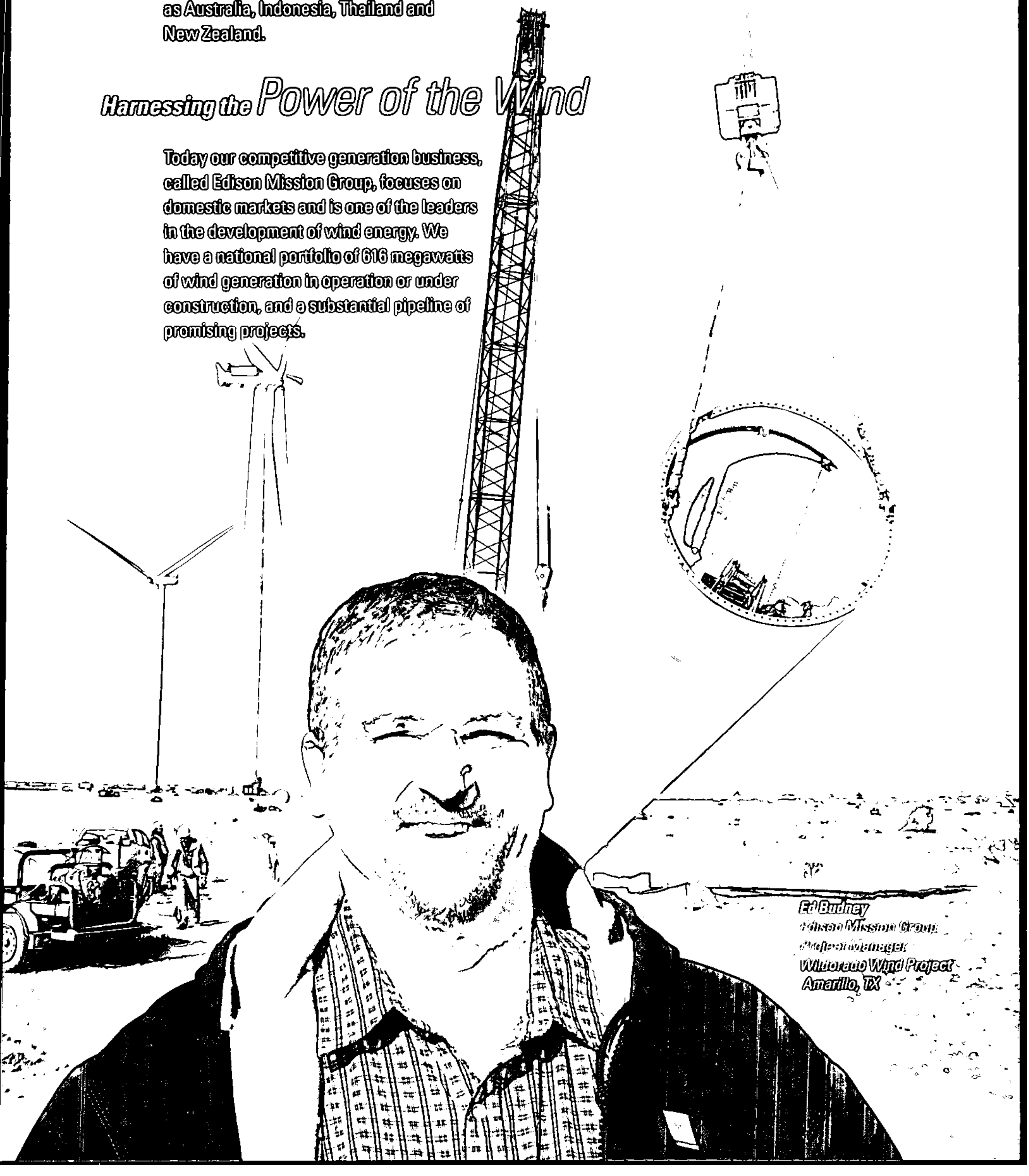
Expanding California's Electricity Highways

Many of the best potential locations for wind, geothermal and other renewable generation are far from existing transmission lines. This project will connect the resource-rich – but remote – Tehachapi region to the power grid, encouraging the development of 4,500 megawatts of renewable energy sources.

Edison International helped to pioneer the independent power business in the United States and led the way internationally with ground-breaking privatizations and private power developments in countries such as Australia, Indonesia, Thailand and New Zealand.

Harnessing the Power of the Wind

Today our competitive generation business, called Edison Mission Group, focuses on domestic markets and is one of the leaders in the development of wind energy. We have a national portfolio of 616 megawatts of wind generation in operation or under construction, and a substantial pipeline of promising projects.



Ed Budney
Edison Mission Group
Project Manager
Wildorado Wind Project
Amarillo, TX

Edison International helped lead the way out of the California power crisis with the construction of new generation when others couldn't and straight talk when others wouldn't. In 2006 we stepped forward again to address one of the lingering problems of the crisis: inadequate new power plant construction in California.

Promoting *Reliability in California*

An innovative approach developed by Southern California Edison allocates the benefits and costs of new generation contracts among all customers in our service territory who benefit. SCE as a result has signed agreements that will lead to more than 1,000 megawatts of much-needed new electricity supply.

Peggy Cheng
Southern California Edison
Energy Operations Specialist
Rosemead, CA

At right: SCE can install a device to help customers conserve energy by reducing their air-conditioning use during periods of peak demand.

Below: SCE's advanced meter test facility, Westminster, CA

Southern California Edison's award-winning energy-efficiency programs helped customers save more than four billion kilowatt-hours of electricity usage over the last five years. That's enough to power 500,000 homes for a year, and reduce greenhouse gas emissions by more than two million tons.

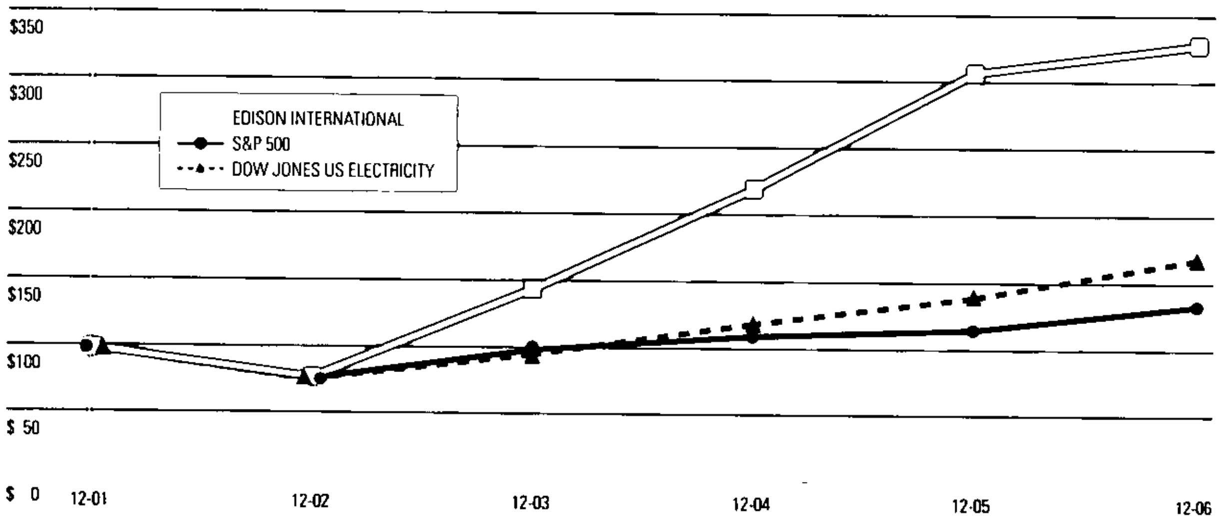
Encouraging Smart Energy Usage

Now we are setting the industry standard for next-generation "smart" electricity meters to provide customers with significantly more control over their energy use and costs, which, in turn, can provide a better means to manage demand on the electricity system during times of peak usage.

Edison International Leading the Way in Electricity

Edison International, through its subsidiaries, is a generator and distributor of electric power and an investor in infrastructure and energy assets, including renewable energy. Headquartered in Rosemead, California, Edison International is the parent company of Southern California Edison – a regulated electric utility – and Edison Mission Group, a competitive power generation business and parent company to Edison Mission Energy and Edison Capital.

Comparison of Five-Year Cumulative Total Return*



*$100 invested on 12/31/01 in stock or index-including reinvestment of dividends. Fiscal year ending December 31

	12/01	12/02	12/03	12/04	12/05	12/06
Edison International	100.00	78.48	145.23	220.87	308.38	330.02
S & P 500	100.00	77.90	100.24	111.15	116.61	135.03
Dow Jones US Electricity	100.00	77.33	96.72	120.28	140.57	169.88

Edison Mission Group: EBITDA – Non-GAAP Reconciliation

	2005	2006
Net income	$443	$432
Addback (Deduct):		
Cumulative effect of change in accounting, net of tax	1	(1)
Discontinued operations	(30)	(97)
Income (loss) from continuing operations	414	334
Interest expense	435	409
Interest income	(74)	(118)
Income taxes (benefits)	163	154
Depreciation and Amortization	147	157
EBITDA	1,085	936

Table of Contents

(This page intentionally left blank)

Glossary

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

AFUDC	allowance for funds used during construction
ARO(s)	asset retirement obligation(s)
Brooklyn Navy Yard	Brooklyn Navy Yard Cogeneration Partners, L.P.
Btu	British Thermal units
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
Commonwealth Edison	Commonwealth Edison Company
CDWR	California Department of Water Resources
CEC	California Energy Commission
CEMA	catastrophic event memorandum account
CPS	Combined Pollutant Standard
CPSD	Consumer Protection and Safety Division
CPUC	California Public Utilities Commission
District Court	U.S. District Court for the District of Columbia
DOE	United States Department of Energy
Duke	Duke Energy Trading and Marketing, LLC
DWP	Los Angeles Department of Water & Power
EITF	Emerging Issues Task Force
EITF No. 01-8	EITF Issue No. 01-8, Determining Whether an Arrangement Contains a Lease
EME	Edison Mission Energy
EME Homer City	EME Homer City Generation L.P.
EMG	Edison Mission Group Inc.
EMMT	Edison Mission Marketing & Trading, Inc.
EPS	earnings per share
ERRA	energy resource recovery account
Exelon Generation	Exelon Generation Company LLC
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN 46(R)	Financial Accounting Standards Interpretation No. 46, Consolidation of Variable Interest Entities
FIN 46(R)-6	Financial Accounting Standards Interpretation No. 46(R)-6, Determining Variability to be Considered in Applying FIN 46(R)
FIN 47	Financial Accounting Standards Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations
FIN 48	Financial Accounting Standards Interpretation No. 48, Accounting for Uncertainty in Income Taxes — an interpretation of FAS 109
FSP	FASB Staff Position
FSP FAS 13-2	FASB Staff Position FAS 13-2, Accounting for a Change or Projected Change in the Timing of Cash Flows Relating to Income Taxes Generated by a Leveraged Lease Transaction
GHG	greenhouse gas
GRC	General Rate Case
Illinois EPA	Illinois Environmental Protection Agency
IPM	a consortium comprised of International Power plc (70%) and Mitsui & Co., Ltd. (30)%
IRS	Internal Revenue Service

ISO	California Independent System Operator
kWh(s)	kilowatt-hour(s)
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
MECIBV	MEC International B.V.
MEHC	Mission Energy Holding Company
Midland Cogen	Midland Cogeneration Venture
Midway-Sunset	Midway-Sunset Cogeneration Company
Midwest Generation	Midwest Generation, LLC
Mohave	Mohave Generating Station
Moody's	Moody's Investors Service
MW	megawatts
MWh	megawatt-hours
NAPP	Northern Appalachian
Ninth Circuit	United States Court of Appeals for the Ninth Circuit
NO_X	nitrogen oxide
NRC	Nuclear Regulatory Commission
PADEP	Pennsylvania Department of Environmental Protection
Palo Verde	Palo Verde Nuclear Generating Station
PBOP(s)	postretirement benefits other than pension(s)
PBR	performance-based ratemaking
PG&E	Pacific Gas & Electric Company
PJM	PJM Interconnection, LLC
PRB	Powder River Basin
PX	California Power Exchange
QF(s)	qualifying facility(ies)
RGGI	Regional Greenhouse Gas Initiative
RICO	Racketeer Influenced and Corrupt Organization
S&P	Standard & Poor's
SAB	Staff Accounting Bulletin
San Onofre	San Onofre Nuclear Generating Station
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric
SFAS	Statement of Financial Accounting Standards issued by the FASB
SFAS No. 71	Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation
SFAS No. 98	Statement of Financial Accounting Standards No. 98, Sale-Leaseback Transactions Involving Real Estate
SFAS No. 123(R)	Statement of Financial Accounting Standards No. 123(R), Share-Based Payment (revised 2004)
SFAS No. 133	Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities
SFAS No. 143	Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations
SFAS No. 144	Statement of Financial Accounting Standards No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets
SFAS No. 157	Statement of Financial Accounting Standards No. 157, Fair Value Measurements

SFAS No. 158	Statement of Financial Accounting Standards No. 158, Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans
SIP(s)	State Implementation Plan(s)
SO_2	sulfur dioxide
SRP	Salt River Project Agricultural Improvement and Power District
the Tribes	Navajo Nation and Hopi Tribe
US EPA	United States Environmental Protection Agency
VIE(s)	variable interest entity(ies)

INTRODUCTION

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

- the ability of Edison International to meet its financial obligations and to pay dividends on its common stock if its subsidiaries are unable to pay dividends;
- the ability of SCE to recover its costs in a timely manner from its customers through regulated rates;
- decisions and other actions by the CPUC, the FERC and other regulatory authorities and delays in regulatory actions;
- market risks affecting SCE's energy procurement activities;
- access to capital markets and the cost of capital;
- changes in interest rates, rates of inflation and foreign exchange rates;
- governmental, statutory, regulatory or administrative changes or initiatives affecting the electricity industry, including the market structure rules applicable to each market;
- environmental regulations that could require additional expenditures or otherwise affect the cost and manner of doing business;
- risks associated with operating nuclear and other power generating facilities, including operating risks, nuclear fuel storage, equipment failure, availability, heat rate, output, and availability and cost of spare parts and repairs;
- the availability of labor, equipment and materials;
- the ability to obtain sufficient insurance, including insurance relating to SCE's nuclear facilities;
- effects of legal proceedings, changes in or interpretations of tax laws, rates or policies, and changes in accounting standards;
- the outcome of disputes with the IRS and other tax authorities regarding tax positions taken by Edison International;
- supply and demand for electric capacity and energy, and the resulting prices and dispatch volumes, in the wholesale markets to which EMG's generating units have access;
- the cost and availability of coal, natural gas, fuel oil, nuclear fuel, and associated transportation;
- the cost and availability of emission credits or allowances for emission credits;
- transmission congestion in and to each market area and the resulting differences in prices between delivery points;
- the ability to provide sufficient collateral in support of hedging activities and purchased power and fuel;
- the risk of counter-party default in hedging transactions or fuel contracts;

- the extent of additional supplies of capacity, energy and ancillary services from current competitors or new market entrants, including the development of new generation facilities and technologies;
- the difficulty of predicting wholesale prices, transmission congestion, energy demand and other aspects of the complex and volatile markets in which EMG and its subsidiaries participate;
- general political, economic and business conditions;
- weather conditions, natural disasters and other unforeseen events; and
- changes in the fair value of investments and other assets.

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

Edison International is engaged in the business of holding, for investment, the common stock of its subsidiaries. Edison International's principal operating subsidiaries are SCE, EME and Edison Capital. EMG is the holding company for its principal wholly owned subsidiaries, MEHC and Edison Capital. MEHC is the holding company for its wholly owned subsidiary, EME. Beginning in 2006, MEHC and Edison Capital are presented on a consolidated basis as EMG. This change has been made to reflect the integration of management and personnel at MEHC and Edison Capital.

In this MD&A, except when stated to the contrary, references to each of Edison International, SCE, EMG, MEHC, EME or Edison Capital mean each such company with its subsidiaries on a consolidated basis. References to Edison International (parent) or parent company and MEHC (parent) mean Edison International or MEHC on a stand-alone basis, not consolidated with its subsidiaries.

This MD&A is presented in 12 major sections. The company-by-company discussion of SCE, EMG, and Edison International (parent) includes discussions of liquidity, market risk exposures, and other matters (as relevant to each principal business segment). The remaining sections discuss Edison International on a consolidated basis. The consolidated sections should be read in conjunction with the discussion of each company's section.

EDISON INTERNATIONAL

EDISON INTERNATIONAL: MANAGEMENT OVERVIEW

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

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

- Execution of EMG's plans for growth of its generation development business – EMG has substantially expanded its development of wind projects by entering into joint development agreements with third parties. During 2006, EMG jointly completed development and commenced construction of four new wind projects (totaling 181 MW) with third parties. These projects, together with the Wildorado wind project (161 MW) which was acquired in early 2006, with total construction costs, excluding capitalized interest, estimated to be $270 million, are expected to be completed during 2007. To support completion of wind projects in 2007 and 2008, EMG has purchased wind turbines supporting 487 MW of projects. In June 2006, subsidiaries of EMG and BP America Inc. formed Carson Hydrogen Power LLC for the development of a power project to be located in Carson, California. Carson Hydrogen is a development stage enterprise for a planned industrial gasification project that will integrate proven gasification, power generation and enhanced oil recovery technologies. On November 29, 2006, the project was allocated $90 million of qualifying gasification project credits under Section 48B of the Internal Revenue Code. Carson Hydrogen is conducting preliminary development, including engineering, financial analysis and commercial arrangements, required for project implementation.

- Optimization of the value of EMG's generation portfolio – EMG effectively managed its exposures to market risks associated with energy prices affecting revenue from its Illinois plants and Homer City facilities, as well as its exposures to coal and emission allowances prices. In addition, in September 2006, the first Illinois power procurement auction was held by Commonwealth Edison according to the rules approved by the Illinois Commerce Commission. Through the auction, EMG entered into two load requirements services contracts. Under the terms of these agreements, EMG expects to deliver electricity, capacity and specified ancillary, transmission and load following services necessary to serve a portion of Commonwealth Edison's residential and small commercial customer load. The estimated MWh for 2007, 2008 and 2009 under these energy supply agreements are 8.5 million, 6.2 million and 1.8 million, respectively.

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

Other significant developments in 2006:

- In December 2006, EMG entered into an agreement with the Illinois EPA to reduce mercury, NO_x and SO_2 emissions at its Illinois coal-fired power plants. Implementation of the agreement will require further regulatory proceedings in order to become effective, and once implemented the agreement will provide reasonable certainty of the timing and amount of emissions reductions which will be required of the Illinois plants for these pollutants through 2018. See "Other Developments—Environmental Matters—Federal Air Quality Standards" for further discussion.

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

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

- Managed Growth –
  - Achieving 2007 milestones for SCE's 2007 – 2011 capital investment plan of up to $17.3 billion. The capital investment plan for 2007 and 2008 for CPUC-jurisdictional projects is consistent with capital additions authorized by the CPUC in SCE's 2006 GRC. The capital investment plan for years 2009 through 2011 is subject to regulatory approvals. The capital investment plan includes distribution system refurbishment and expansion, advanced metering implementation, new transmission construction for reliability and renewable energy projects, San Onofre steam generator replacement, and new peaker installation. See "SCE: Liquidity—Capital Expenditures" for further discussion.
  - Diversifying the fuel type of EMG's generation assets through developing and acquiring new renewable energy projects (primarily wind), developing and acquiring natural gas-fired power projects in locations where existing or projected capacity for generation is constrained, and developing new clean coal generation projects such as integrated gasification combined cycle projects.

- Operational Excellence –
  - Edison International has commenced an enterprise-wide project to implement a comprehensive, integrated software system to support the majority of its critical business processes during the next few years. The objective of this initiative is to improve the efficiency and effectiveness of both SCE's and EMG's operations.
  - In 2007, SCE will continue to procure least-cost, best-fit power resources and execute effective hedging strategies consistent with the CPUC approved procurement plan. SCE expects to enter into contracts with new generation projects to be available by summer 2010 and continue to procure renewable resources in support of Renewable Portfolio Standard goals. SCE will also promote policies where SCE's bundled customers do not incur costs different than other load-serving entities, including improving regulatory rules governing returning Direct Access customers, and equal responsibility for renewables procurement, GHG standards, grid reliability costs, and other public policies.
  - In 2007, EMG will continue to optimize the value of its existing generation assets through operational initiatives focused on long-term cost effective maintenance, integration of commercial marketing and trading activities with plant operations to enhance gross margin, and effective participation in regulatory rule-making in markets where EMG operates; and reduce EMG's cash flow volatility from merchant power plants through asset-based commodity hedging activities.

- Environmental – Edison International is subject to numerous federal and state environmental laws and regulations, including those relating to SO_2 and NO_x emissions, mercury emissions, ozone and fine particulate matter emissions, regional haze, water quality, and climate change. The power plants owned or operated by Edison International's subsidiaries, in particular the coal-fired plants will likely be affected by recent and future developments in federal and state environmental laws and regulations. With respect to potential regulation in response to climate change concerns, Edison International will be working in support of sensible time frames, sound allocation of allowances and credits, a common national regime, and other least-cost approaches to achieving valid public goals. See "Other Developments—Environmental Matters" for further discussion.

SOUTHERN CALIFORNIA EDISON COMPANY

SCE: LIQUIDITY

Overview

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

SCE's 2007 estimated cash outflows consist of:

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

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

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

Capital Expenditures

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

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

Significant investments in 2007 are expected to include:

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

Credit Ratings

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

Dividend Restrictions and Debt Covenants

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

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

Margin and Collateral Deposits

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

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

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

Rate Reduction Notes

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

SCE: REGULATORY MATTERS

Overview of Ratemaking Mechanisms

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

Base Rates

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

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

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

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

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

Cost-Recovery Rates

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

CDWR-Related Rates

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

Impact of Regulatory Matters on Customer Rates

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

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

The rate changes implemented during 2006 primarily related to the implementation of SCE's 2006 ERRA forecast, implementation of the 2006 GRC decision and modification of the FERC transmission-related rates.

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

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

Current Regulatory Developments

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

2006 General Rate Case Proceeding

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

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

2006 Cost of Capital Proceeding

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

2007 Cost of Capital Proceeding

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

2006 FERC Rate Case

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

Energy Resource Recovery Account Proceedings

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

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

Resource Adequacy Requirements

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

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

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

Peaker Plant Generation Projects

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

Procurement of Renewable Resources

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

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

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

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

Request for Offers from Renewable Resources

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

Mohave Generating Station and Related Proceedings

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

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

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

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

San Onofre Nuclear Generating Station Steam Generators and Changes in Ownership

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

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

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

Palo Verde Nuclear Generating Station Steam Generators

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

ISO Disputed Charges

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

Scheduling Coordinator Tariff Dispute

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

FERC Refund Proceedings

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

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

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

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

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

Holding Company Order Instituting Rulemaking

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

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

Investigations Regarding Performance Incentives Rewards

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

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

Customer Satisfaction

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

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

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

Employee Injury and Illness Reporting

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

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

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

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

System Reliability

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

CPUC Investigation

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

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

Settlement Agreement with Duke Energy Trading and Marketing, LLC

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

SCE: OTHER DEVELOPMENTS

Navajo Nation Litigation

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

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

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

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

Palo Verde Nuclear Generating Station Outage and Inspection

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

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

Nuclear Insurance

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

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

Spent Nuclear Fuel

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

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

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

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

SCE: MARKET RISK EXPOSURES

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

Interest Rate Risk

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

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

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

Commodity Price Risk

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

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

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

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

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

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

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

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

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

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

Credit Risk

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

EDISON MISSION GROUP INC.

EMG: LIQUIDITY

MEHC (parent)'s Liquidity

MEHC (parent) has a 100% ownership interest in EME, which itself operates through its subsidiaries and affiliates as described further below. MEHC (parent) has no business activities other than through its ownership interest in EME and has outstanding approximately $800 million of 13.50% senior secured notes due in 2008.

At December 31, 2006, MEHC (parent) had cash and cash equivalents of $28 million (excluding amounts held by EME and its subsidiaries). MEHC's (parent's) ability to honor its obligations under the senior secured notes is substantially dependent upon the receipt of dividends from EME and the receipt of tax-allocation payments from MEHC's parent, EMG, and ultimately Edison International. See "EME's Liquidity as a Holding Company—Intercompany Tax-Allocation Agreement." Dividends to MEHC (parent) from EME are limited based on EME's earnings and cash flow, terms of restrictions contained in EME's corporate credit facility, business and tax considerations and restrictions imposed by applicable law.

Dividends to MEHC (parent)

In January 2006, EME made total dividend payments of $11.5 million to MEHC (parent). In July 2006, EME made a dividend payment of $39 million to MEHC (parent). In January 2007, EME made total dividend payments of $26 million to MEHC. These payments were used to pay interest on MEHC's senior secured notes.

In 2004, EME made dividend payments totaling $74 million to MEHC (parent). These payments were used together with cash on hand to repurchase $100 million of the principal amount of MEHC (parent)'s term loan. In January 2005, EME made total dividend payments of $360 million to MEHC (parent). A portion of these payments was used to repay the remaining $285 million of MEHC (parent)'s term loan, plus interest.

Dividend Restriction in EME's Corporate Credit Agreement

EME's corporate credit agreement restricts EME's ability to make distributions if an event of default were to occur and be continuing after giving effect to the distribution.

EME's Liquidity

At December 31, 2006, EME and its subsidiaries had cash and cash equivalents and short-term investments of $1.8 billion, and EME had a total of $968 million of available borrowing capacity under its $500 million corporate credit facility and a $500 million working capital facility at Midwest Generation. EME's consolidated debt at December 31, 2006 was $3.2 billion. In addition, EME's subsidiaries had $4.2 billion of long-term lease obligations related to the sale-leaseback transactions that are due over periods ranging up to 28 years.

MEHC's Financing Developments

During June 2006, EME replaced its $98 million credit agreement with a new credit agreement that provides for a $500 million senior secured revolving loan and letter of credit facility and matures on June 15, 2012. As security for its obligations under this credit facility, EME pledged its ownership interests in the holding companies through which it owns its interests in the Illinois plants, the Homer City facilities, the Westside projects and the Sunrise project. EME also granted a security interest in an account into which all distributions received by it from the Big 4 projects will be deposited. EME will be free to use these proceeds unless an event of default occurs under the credit facility.

Also in June 2006, EME completed a private offering of $500 million aggregate principal amount of its 7.50% senior notes due June 15, 2013 and $500 million aggregate principal amount of its 7.75% senior notes due June 15, 2016. EME pays interest on the senior notes on June 15 and December 15 of each year, beginning on December 15, 2006. The senior notes are redeemable by EME at any time at a price equal to 100% of the principal amount of, plus accrued and unpaid interest and liquidated damages, if any, on the senior notes plus a "make-whole" premium. During the fourth quarter of 2006, EME completed an exchange of the senior notes issued in the private offering for new senior notes (with the same terms and conditions as the existing senior notes) registered under the Securities Act. EME used the net proceeds of the offering of the senior notes, together with cash on hand, to repay debt.

MEHC's Capital Expenditures

At December 31, 2006, the three-year estimated capital expenditures by EME's subsidiaries related to existing projects, corporate activities and turbine commitments were as follows:

In millions	2007	2008	2009
Illinois Plants			
Plant capital expenditures	$ 54	$ 45	$ 26
Environmental expenditures	21	38	66
Homer City Facilities			
Plant capital expenditures	19	26	20
Environmental expenditures	9	9	15
Wind Projects			
Projects under construction	176	—	—
Turbine commitments	463	26	—
Corporate capital expenditures	19	7	7
Total	$ 761	$ 151	$ 134

Expenditures for Existing Projects

Plant capital expenditures relate to nonenvironmental projects such as upgrades to boiler and turbine controls and dust collection/mitigation systems, a spare main power transformer, railroad interconnection and an expansion of a coal cleaning plant refuse site. Environmental expenditures relate to environmental projects such as mercury emission monitoring and control and SCR performance improvements at the Homer City facilities and various projects at the Illinois plants to achieve specified emissions reductions such as installation of mercury controls. EME plans to finance these expenditures with financings, cash on hand or cash generated from operations. See further discussion regarding these and possible additional capital expenditures, including environmental control equipment at the Homer City facilities, under "Other Developments—Environmental Matters—Air Quality Standards—Water Quality Regulation—Climate Change."

Expenditures for New Projects

EME expects to make substantial investments in new projects during the next three years. In addition to the capital expenditures to purchase turbines set forth in the above table, EME has entered into an agreement to purchase 60 additional turbines (totaling 150 MW) subsequent to December 31, 2006, subject to certain conditions, and has entered into a letter of intent to purchase 300 turbines (totaling 630 MW) for delivery in 2008 and 2009. The purchase of these turbines is subject to completion of a definitive turbine purchase agreement. Total capital expenditures under these agreements would be approximately $875 million, not including the cost to complete construction, if the maximum number of turbines were purchased.

MEHC's Credit Ratings

Overview

Credit ratings for MEHC and its subsidiaries, EME, Midwest Generation and EMMT, at December 31, 2006, were as follows:

	Moody's Rating	S&P Rating
MEHC	B2	B
EME	B1	BB-
Midwest Generation:		
First priority senior secured rating	Baa3	BB
Second priority senior secured rating	Ba2	B+
EMMT	Not Rated	BB-

On September 27, 2006, Moody's raised Midwest Generation's first priority senior secured rating to Baa3 from Ba2 and its second priority senior secured rating to Ba2 from Ba3. On September 29, 2006, S&P raised the credit rating of MEHC to B from B-. S&P also raised the credit ratings of EME and EMMT to BB- from B+. In addition, S&P raised Midwest Generation's first priority senior secured rating to BB from BB- and its second priority senior secured rating to B+ from B.

MEHC cannot provide assurance that its current credit ratings or the credit ratings of its subsidiaries will remain in effect for any given period of time or that one or more of these ratings will not be lowered. MEHC notes that these credit ratings are not recommendations to buy, sell or hold its securities and may be revised at any time by a rating agency.

MEHC does not have any "rating triggers" contained in subsidiary financings that would result in it or EME being required to make equity contributions or provide additional financial support to its subsidiaries.

Credit Rating of EMMT

The Homer City sale-leaseback documents restrict EME Homer City's ability to enter into trading activities, as defined in the documents, with EMMT to sell forward the output of the Homer City facilities if EMMT does not have an investment grade credit rating from S&P or Moody's or, in the absence of those ratings, if it is not rated as investment grade pursuant to EME's internal credit scoring procedures. These documents include a requirement that the counterparty to such transactions, and EME Homer City, if acting as seller to an unaffiliated third party, be investment grade. EME currently sells all the output from the Homer City facilities through EMMT, which has a below investment grade credit rating, and EME Homer City is not rated. Therefore, in order for EME to continue to sell forward the output of the Homer City facilities, either: (1) EME must obtain consent from the sale-leaseback owner participant to permit EME Homer City to sell directly into the market or through EMMT; or (2) EMMT must provide assurances of performance consistent with the requirements of the sale-leaseback documents. EME has obtained a consent from the sale-leaseback owner participant that will allow EME Homer City to enter into such sales, under specified conditions, through December 31, 2008. EME Homer City continues to be in compliance with the terms of the consent. EME is permitted to sell the output of the Homer City facilities into the spot market at any time. See "EMG: Market Risk Exposures—MEHC's Commodity Price Risk—Energy Price Risk Affecting Sales from the Homer City Facilities."

MEHC's Margin, Collateral Deposits and Other Credit Support for Energy Contracts

In connection with entering into contracts in support of EME's hedging and energy trading activities (including forward contracts, transmission contracts and futures contracts), EME's subsidiary, EMMT, has entered into agreements to mitigate the risk of nonperformance. Because the credit ratings of EMMT and EME are below investment grade, EME has historically provided collateral in the form of cash and letters of credit for the benefit of counterparties related to accounts payable and unrealized losses in connection with these hedging and trading activities. At December 31, 2006, EMMT had deposited $31 million in cash with brokers in margin accounts in support of futures contracts and had deposited $42 million with counterparties in support of forward energy and transmission contracts. In addition, EME had issued letters of credit of $6 million in support of commodity contracts at December 31, 2006.

Future cash collateral requirements may be higher than the margin and collateral requirements at December 31, 2006, if wholesale energy prices increase or the amount hedged increases. EME estimates that margin and collateral requirements for energy contracts outstanding as of December 31, 2006 could increase by approximately $610 million over the remaining life of the contracts using a 95% confidence level.

Midwest Generation has cash on hand and a $500 million working capital facility to support margin requirements specifically related to contracts entered into by EMMT related to the Illinois plants. At December 31, 2006, Midwest Generation had available $495 million of borrowing capacity under this credit facility. As of December 31, 2006, Midwest Generation had $43 million in loans receivable from EMMT for margin advances. In addition, EME has cash on hand and a $500 million working capital facility to provide credit support to subsidiaries. See "—MEHC's Financing Developments" and "—EME's Liquidity as a Holding Company" for further discussion.

EME's Liquidity as a Holding Company

Overview

At December 31, 2006, EME had corporate cash and cash equivalents and short-term investments of $1.5 billion to meet liquidity needs. See "—EME's Liquidity." Cash distributions from EME's subsidiaries and partnership investments and unused capacity under its corporate credit facility represent EME's major sources of liquidity to meet its cash requirements. The timing and amount of distributions from EME's subsidiaries may be affected by many factors beyond its control. See "—MEHC's Dividend Restrictions in Major Financings."

Historical Distributions Received By EME

The following table is presented as an aid in understanding the cash flow of EME's continuing operations and its various subsidiary holding companies which depend on distributions from subsidiaries and affiliates to fund general and administrative costs and debt service costs of recourse debt.

In millions Year Ended December 31,	**2006**	2005	2004
Distributions from Consolidated Operating Projects:			
Edison Mission Midwest Holdings (Illinois plants)	**$ 542**[(1)]	$ 330[(2)]	$ 88
EME Homer City (Homer City facilities)	**—**	86	61
Holding company for Storm Lake project	**11**	—	—
Holding companies of other consolidated operating projects	**5**	1	1
Distributions from Unconsolidated Operating Projects:			
Edison Mission Energy Funding Corp. (Big 4 Projects)[(3)]	**116**	122	108
Sunrise Power Company	**22**	20	19
Holding company for Doga project	**—**	17	15
Holding companies for Westside projects	**16**	17	18
Holding companies of other unconsolidated operating projects	**1**	5	3
Total Distributions	**$ 713**	$ 598	$ 313

(1) Subsequent to December 31, 2006, Edison Mission Midwest Holdings made an additional distribution of $117 million.

(2) In April 2005, EME made a capital contribution of $300 million which was used to repay debt.

(3) The Big 4 projects consist of investments in the Kern River project, Midway-Sunset project, Sycamore project and Watson project. Distributions reflect the amount received by EME after debt service payments by Edison Mission Energy Funding Corp.

Intercompany Tax-Allocation Agreement

MEHC (parent) and EME are included in the consolidated federal and combined state income tax returns of Edison International and are eligible to participate in tax-allocation payments with other subsidiaries of Edison International in circumstances where domestic tax losses are incurred. The right of MEHC (parent) and EME to receive and the amount of and timing of tax-allocation payments are dependent on the inclusion of MEHC (parent) and EME, respectively, in the consolidated income tax returns of Edison International and its subsidiaries and other factors, including the consolidated taxable income of Edison International and its subsidiaries, the amount of net operating losses and other tax items of MEHC (parent), EME, its subsidiaries, and other subsidiaries of Edison International and specific procedures regarding allocation of state taxes. MEHC (parent) and EME receive tax-allocation payments for tax losses when and to the extent that the consolidated Edison International group generates sufficient taxable income in order to be able to utilize MEHC's (parent's) or EME's consolidated tax losses in the consolidated income tax returns for Edison International and its subsidiaries. Based on the application of the factors cited above, MEHC (parent) and EME are obligated during periods they generate taxable income to make payments under the tax-allocation agreements. EME made net tax-allocation payments to Edison International of $151 million and $129 million in 2006 and 2005, respectively. MEHC (parent) received tax-allocation payments from Edison International of $43 million and $93 million in 2006 and 2005, respectively.

MEHC's Dividend Restrictions in Major Financings

General

Each of EME's direct or indirect subsidiaries is organized as a legal entity separate and apart from EME and its other subsidiaries. Assets of EME's subsidiaries are not available to satisfy EME's obligations or the obligations of any of its other subsidiaries. However, unrestricted cash or other assets that are available for distribution may, subject to applicable law and the terms of financing arrangements of the parties, be advanced, loaned, paid as dividends or otherwise distributed or contributed to EME or to its subsidiary holding companies.

Key Ratios of MEHC and EME's Principal Subsidiaries Affecting Dividends

Set forth below are key ratios of MEHC and EME's principal subsidiaries required by financing arrangements for the twelve months ended December 31, 2006:

Subsidiary	Financial Ratio	Covenant	Actual
MEHC	Interest Coverage Ratio	Greater than 2.0 to 1	2.79 to 1
Midwest Generation (Illinois plants)	Interest Coverage Ratio	Greater than or equal to 1.40 to 1	5.14 to 1
Midwest Generation (Illinois plants)	Secured Leverage Ratio	Less than or equal to 7.25 to 1	2.17 to 1
EME Homer City (Homer City facilities)	Senior Rent Service Coverage Ratio	Greater than 1.7 to 1	2.32 to 1[(1)]

(1) The senior rent service coverage ratio is determined by dividing net operating cash flow by senior rent. Net operating cash flow represents revenue less operating expenses as defined in the sale-leaseback documents. Revenue during the twelve months ended December 31, 2006 includes $15.5 million from an advance payment from EMMT against future deliveries of power to it under its trading arrangements with EME Homer City.

Midwest Generation Financing Restrictions on Distributions

Midwest Generation is bound by the covenants in its credit agreement and indenture as well as certain covenants under the Powerton-Joliet lease documents with respect to Midwest Generation making payments under the leases. These covenants include restrictions on the ability to, among other things, incur debt, create liens on its property, merge or consolidate, sell assets, make investments, engage in transactions with affiliates, make distributions, make capital expenditures, enter into agreements restricting its ability to make distributions, engage in other lines of business or engage in transactions for any speculative purpose. In addition, the credit agreement contains financial covenants binding on Midwest Generation.

Covenants in Credit Agreement

In order for Midwest Generation to make a distribution, it must be in compliance with covenants specified under its credit agreement. Compliance with the covenants in its credit agreement includes maintaining the following two financial performance requirements:

- At the end of each fiscal quarter, Midwest Generation's consolidated interest coverage ratio for the immediately preceding four consecutive fiscal quarters must be at least 1.40 to 1. The consolidated interest coverage ratio is defined as the ratio of consolidated net income (plus or minus specified amounts as set forth in the credit agreement), to consolidated interest expense (as more specifically defined in the credit agreement).
- Midwest Generation's secured leverage ratio for the 12-month period ended on the last day of the immediately preceding fiscal quarter may be no greater than 7.25 to 1. The secured leverage ratio is defined as the ratio of the aggregate principal amount of Midwest Generation secured debt plus all indebtedness of a subsidiary of Midwest Generation, to the aggregate amount of consolidated net income (plus or minus specified amounts as set forth in the credit agreement).

In addition, Midwest Generation's distributions are limited in amount. Under the terms of Midwest Generation's credit agreement, Midwest Generation is permitted to distribute 75% of its excess cash flow (as defined in the credit agreement). In addition, if equity is contributed to Midwest Generation, Midwest Generation is permitted to distribute 100% of excess cash flow until the aggregate portion of distributions that Midwest Generation attributed to the equity contribution equals the amount of the equity contribution. Because EME made a $300 million equity contribution to Midwest Generation on April 19, 2005, Midwest Generation is permitted to distribute 100% of excess cash flow until the aggregate portion of such distributions attributed to that equity contribution equals $300 million. After taking into account Midwest Generation's most recent distribution in January 2007, $58 million of the equity contribution is still available for this purpose. To the extent Midwest Generation makes a distribution which is not fully attributed to an equity contribution, Midwest Generation is required to make concurrently with such distribution an offer to repay debt in an amount equal to the excess, if any, of one-third of such distribution over the amount attributed to the equity contribution.

Covenants in Indenture

Midwest Generation's indenture contains restrictions on its ability to make a distribution substantially similar to those in the credit agreement. Failure to achieve the conditions required for distributions will not result in a default under the indenture, nor does the indenture contain any other financial performance requirements.

EME Homer City (Homer City Facilities)

EME Homer City completed a sale-leaseback of the Homer City facilities in December 2001. In order to make a distribution, EME Homer City must be in compliance with the covenants specified in the lease agreements, including the following financial performance requirements measured on the date of distribution:

- At the end of each quarter, the senior rent service coverage ratio for the prior twelve-month period (taken as a whole) must be greater than 1.7 to 1. The senior rent service coverage ratio is defined as all income and receipts of EME Homer City less amounts paid for operating expenses, required capital expenditures, taxes and financing fees divided by the aggregate amount of the debt portion of the rent, plus fees, expenses and indemnities due and payable with respect to the lessor's debt service reserve letter of credit.

At the end of each quarter, the equity and debt portions of rent then due and payable must have been paid. The senior rent service coverage ratio (discussed above) projected for each of the prospective two 12-month periods must be greater than 1.7 to 1. No more than two rent default events may have occurred, whether or not cured. A rent default event is defined as the failure to pay the equity portion of the rent within five business days of when it is due.

EME Corporate Credit Facility Restrictions on Distributions from Subsidiaries

EME's corporate credit facility contains covenants that restrict its ability, and the ability of several of its subsidiaries, to make distributions. This restriction binds the subsidiaries through which EME owns the Westside projects, the Sunrise project, the Illinois plants, the Homer City facilities and the Big 4 projects. These subsidiaries would not be able to make a distribution to EME if an event of default were to occur and be continuing under EME's corporate credit facility after giving effect to the distribution.

In addition, EME granted a security interest in an account into which all distributions received by it from the Big 4 projects are deposited. EME is free to use these distributions unless and until an event of default occurs under its corporate credit facility.

As of December 31, 2006, EME had no borrowings and $27 million of letters of credit outstanding under this credit facility.

Edison Capital's Liquidity

Overview

Edison Capital's main sources of liquidity are tax-allocation payments from Edison International, distributions from its global infrastructure fund investments and lease rents. During 2006, Edison Capital received $135 million in net tax-allocation payments, $78 million in global infrastructure fund distributions and $22 million in lease rent payments.

As of December 31, 2006, Edison Capital had unrestricted cash and cash equivalents of $375 million and long-term debt, including current maturities, of $164 million.

Credit Ratings

At December 31, 2006, Edison Capital's long-term debt had credit ratings of Ba1 and BB+ from Moody's and S&P, respectively.

Dividend Restrictions and Debt Covenants

Edison Capital's ability to make dividend payments to Edison International (parent) is restricted by debt covenants (see "Edison International (Parent): Liquidity" for further discussion). In 2006, Edison Capital complied with its debt covenants.

Intercompany Tax-Allocation Payments

Edison Capital is included in the consolidated federal and combined state income tax returns of Edison International and is eligible to participate in tax-allocation payments with Edison International and other subsidiaries of Edison International. See "—EME's Liquidity as a Holding Company—Intercompany Tax-Allocation Agreement" for additional information regarding these arrangements. The amount received is net of payments made to Edison International. (See "Other Developments—Federal and State Income Taxes" for further discussion of tax-related issues regarding Edison Capital's leveraged leases).

Federal Income Taxes

Edison International received Revenue Agent Reports from the IRS in August 2002 and in January 2005 asserting deficiencies in federal corporate income taxes with respect to audits of its 1994 to 1996 and 1997 to 1999 tax years, respectively. Among the issues raised were items related to Edison Capital. See "Other Developments—Federal and State Income Taxes" for further discussion of these matters.

EMG: OTHER DEVELOPMENTS

FERC Notice Regarding Investigatory Proceeding against EMMT

At the end of October 2006, EMMT was advised by the enforcement staff at the FERC that it is prepared to recommend that the FERC initiate a formal investigatory proceeding and seek monetary sanctions against EMMT for alleged violation of the FERC's rules with respect to certain bidding practices employed by EMMT. EMMT is engaged in discussions with the staff to explore the possibility of resolution of this matter. Should a formal proceeding be commenced, EMMT will be entitled to contest any alleged violations before the FERC and an appropriate court. EME believes that EMMT has complied with the FERC's rules and intends to contest vigorously any allegation of violation. EME cannot predict at this time the outcome of this matter or estimate the possible liability should the outcome be adverse.

MEHC: Homer City Transformer Failure

On January 29, 2006, the main power transformer on Unit 3 of the Homer City facilities failed resulting in a suspension of operations at this unit. Homer City secured a replacement transformer and Unit 3 returned to service on May 5, 2006. Homer City has adjusted its previously planned outage schedules for Unit 3 and the other Homer City units in order to minimize to the extent practicable overall outage activities for all units through the first half of 2007. The main transformer failure resulted in claims under Homer City's property and business interruption insurance policies. At December 31, 2006, Homer City had a $17 million receivable related to these claims. Resolution of the claims is subject to a number of uncertainties, including computations of the lost profit during the outage period.

EMG: MARKET RISK EXPOSURES

Introduction

MEHC's primary market risk exposures are associated with the sale of electricity and capacity from and the procurement of fuel for its merchant power plants. These market risks arise from fluctuations in electricity, capacity and fuel prices, emission allowances, and transmission rights. Additionally, MEHC's financial results can be affected by fluctuations in interest rates. MEHC manages these risks in part by using derivative financial instruments in accordance with established policies and procedures.

MEHC's Commodity Price Risk

Overview

EME's revenue and results of operations of its merchant power plants will depend upon prevailing market prices for capacity, energy, ancillary services, emission allowances or credits, coal, natural gas and fuel oil, and associated transportation costs in the market areas where EME's merchant plants are located. Among the factors that influence the price of energy, capacity and ancillary services in these markets are:

- prevailing market prices for coal, natural gas and fuel oil, and associated transportation;
- the extent of additional supplies of capacity, energy and ancillary services from current competitors or new market entrants, including the development of new generation facilities and/or technologies that may be able to produce electricity at a lower cost than EME's generating facilities and/or increased access by competitors to EME's markets as a result of transmission upgrades;
- transmission congestion in and to each market area and the resulting differences in prices between delivery points;
- the market structure rules established for each market area and regulatory developments affecting the market areas, including any price limitations and other mechanisms adopted to address volatility or illiquidity in these markets or the physical stability of the system;
- the cost and availability of emission credits or allowances;

- the availability, reliability and operation of competing power generation facilities, including nuclear generating plants, where applicable, and the extended operation of such facilities beyond their presently expected dates of decommissioning;
- weather conditions prevailing in surrounding areas from time to time; and
- changes in the demand for electricity or in patterns of electricity usage as a result of factors such as regional economic conditions and the implementation of conservation programs. A discussion of commodity price risk for the Illinois plants and the Homer City facilities is set forth below.

Introduction

EME's merchant operations expose it to commodity price risk, which represents the potential loss that can be caused by a change in the market value of a particular commodity. Commodity price risks are actively monitored by a risk management committee to ensure compliance with EME's risk management policies. Policies are in place which define risk management processes, and procedures exist which allow for monitoring of all commitments and positions with regular reviews by EME's risk management committee. Despite this, there can be no assurance that all risks have been accurately identified, measured and/or mitigated.

In addition to prevailing market prices, EME's ability to derive profits from the sale of electricity will be affected by the cost of production, including costs incurred to comply with environmental regulations. The costs of production of the units vary and, accordingly, depending on market conditions, the amount of generation that will be sold from the units is expected to vary.

EME uses "value at risk" to identify, measure, monitor and control its overall market risk exposure in respect of its Illinois plants, its Homer City facilities, and its trading positions. The use of value at risk allows management to aggregate overall commodity risk, compare risk on a consistent basis and identify the risk factors. Value at risk measures the possible 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 the use of stress testing and worst-case scenario analysis for key risk factors, as well as stop-loss limits and counterparty credit exposure limits.

Hedging Strategy

To reduce its exposure to market risk, EME hedges a portion of its merchant portfolio risk through EMMT, an EME subsidiary engaged in the power marketing and trading business. To the extent that EME does not hedge its merchant portfolio, the unhedged portion will be subject to the risks and benefits of spot market price movements. Hedge transactions are primarily implemented through:

- the use of contracts cleared on the Intercontinental Trading Exchange and the New York Mercantile Exchange,
- forward sales transactions entered into on a bilateral basis with third parties, including electric utilities and power marketing companies, and
- full requirements services contracts or load requirements services contracts for the procurement of power for electric utilities' customers, with such services including the delivery of a bundled product including, but not limited to, energy, transmission, capacity, and ancillary services, generally for a fixed unit price.

The extent to which EME enters into contracts to hedge its market price risk depends on several factors. First, EME evaluates over-the-counter market prices to determine whether sales at forward market prices are sufficiently attractive compared to assuming the risk associated with fluctuating spot market sales. Second, EME's ability to enter into hedging transactions depends upon its and Midwest Generation's credit capacity and upon the forward sales markets having sufficient liquidity to enable EME to identify appropriate counterparties for hedging transactions.

In the case of hedging transactions related to the generation and capacity of the Illinois plants, Midwest Generation is permitted to use its working capital facility and cash on hand to provide credit support for these hedging transactions entered into by EMMT under an energy services agreement between Midwest Generation and EMMT. Utilization of this credit facility in support of hedging transactions provides additional liquidity support for implementation of EME's contracting strategy for the Illinois plants. In the case of hedging transactions related to the generation and capacity of the Homer City facilities, credit support is provided by EME pursuant to intercompany arrangements between it and EMMT. See "—MEHC's Credit Risk" below.

Recent Hedging Developments

In 2006, EMMT entered into agreements with third parties to hedge the price risk for power from the Illinois plants for 2007, 2008 and 2009 (using the Northern Illinois Hub as a reference point). Under the terms of these agreements, EME has guaranteed the obligations of EMMT, but neither EME nor EMMT is required to post margin, provide liens on property or provide other collateral to support the obligations under the agreements.

EMMT participated in an Illinois auction in September 2006, which resulted in its entry into two load requirements contracts with Commonwealth Edison with periods of seventeen months and twenty-nine months, beginning January 1, 2007. Under load requirements services contracts, the amount of power sold is a portion of the retail load of the purchasing utility and can vary significantly with variations in that retail load. Retail load depends upon a number of factors, including the time of day, the time of the year and the utility's number of new and continuing customers.

Energy Price Risk Affecting Sales from the Illinois Plants

All the energy and capacity from the Illinois plants is sold under terms, including price and quantity, arranged by EMMT with customers through a combination of bilateral agreements (resulting from negotiations or from auctions), forward energy sales and spot market sales. As discussed further below, power generated at the Illinois plants is generally sold into the PJM market.

Midwest Generation sells its power into PJM at spot prices based upon locational marginal pricing. Hedging transactions related to the generation of the Illinois plants are generally entered into at the Northern Illinois Hub in PJM, and may also be entered into at other trading hubs, including the AEP/Dayton Hub in PJM and the Cinergy Hub in the Midwest Independent Transmission System Operator. These trading hubs have been the most liquid locations for hedging purposes. However, hedging transactions which settle at points other than the Northern Illinois Hub are subject to the possibility of basis risk. See "—Basis Risk" below for further discussion.

PJM has a short-term market, which establishes an hourly clearing price. The Illinois plants are situated in the PJM control area and are physically connected to high-voltage transmission lines serving this market.

The following table depicts the average historical market prices for energy per MWh during 2006, 2005 and 2004.

	2006[1]	2005[1]	2004
January	**$ 42.27**	$ 38.36	$ 27.88[2]
February	**42.66**	34.92	29.98[2]
March	**42.50**	45.75	30.66[2]
April	**43.16**	38.98	27.88[2]
May	**39.96**	33.60	34.05[1]
June	**34.80**	42.45	28.58[1]
July	**51.82**	50.87	30.92[1]
August	**54.76**	60.09	26.31[1]
September	**31.87**	53.30	27.98[1]
October	**37.80**	49.39	30.93[1]
November	**41.90**	44.03	29.15[1]
December	**33.57**	64.99	29.90[1]
Yearly Average	**$ 41.42**	$ 46.39	$ 29.52

(1) Represents average historical market prices for energy as quoted for sales into the Northern Illinois Hub. Energy prices were calculated at the Northern Illinois Hub delivery point using hourly real-time prices as published by PJM.

(2) Represents average historical market prices for energy "Into ComEd." Energy prices were determined by obtaining broker quotes and other public price sources for "Into ComEd" delivery points.

Forward market prices at the Northern Illinois Hub fluctuate as a result of a number of factors, including natural gas prices, transmission congestion, changes in market rules, electricity demand (which in turn is affected by weather, economic growth, and other factors), plant outages in the region, and the amount of existing and planned power plant capacity. The actual spot prices for electricity delivered by the Illinois plants into these markets may vary materially from the forward market prices set forth in the table below.

The following table sets forth the forward month-end market prices for energy per MWh for the calendar year 2007 and calendar year 2008 "strips," which are defined as energy purchases for the entire calendar year, as quoted for sales into the Northern Illinois Hub during 2006:

	24-Hour Northern Illinois Hub Forward Energy Prices[1]	
	2007	2008
January 31, 2006	$ 51.25	$ 49.01
February 28, 2006	45.61	44.74
March 31, 2006	48.61	48.58
April 30, 2006	51.38	49.88
May 31, 2006	44.92	44.89
June 30, 2006	45.49	45.10
July 31, 2006	48.93	47.67
August 31, 2006	48.68	48.40
September 30, 2006	44.31	45.09
October 31, 2006	44.44	45.63
November 30, 2006	46.35	46.66
December 31, 2006	41.00	45.14

(1) Energy prices were determined by obtaining broker quotes and information from other public sources relating to the Northern Illinois Hub delivery point.

The following table summarizes Midwest Generation's hedge position at December 31, 2006:

	2007	2008	2009
Energy Only Contracts[1]			
MWh	16,323,600	10,854,400	2,048,000
Average price/MWh[2]	$ 48.39	$ 61.33	$ 60.00
Load Requirements Services Contracts			
Estimated MWh[3]	8,522,380	6,209,315	1,805,456
Average price/MWh[4]	$ 64.13	$ 64.01	$ 63.65
Total estimated MWh	24,845,980	17,063,715	3,853,456

(1) Primarily at Northern Illinois Hub.

(2) The energy only contracts include forward contracts for the sale of power and futures contracts during different periods of the year and the day. Market prices tend to be higher during on-peak periods and during summer months, although there is significant variability of power prices during different periods of time. Accordingly, the above hedge position at December 31, 2006 is not directly comparable to the 24-hour Northern Illinois Hub prices set forth above.

(3) Under a load requirements services contract, the amount of power sold is a portion of the retail load of the purchasing utility and thus can vary significantly with variations in that retail load. Retail load depends upon a number of factors, including the time of day, the time of the year and the utility's number of new and continuing customers. Estimated MWh have been forecast based on historical patterns and on assumptions regarding the factors that may affect retail loads in the future. The actual load will vary from that used for the above estimate, and the amount of variation may be material.

(4) The average price per MWh under a load requirements services contract (which is subject to a seasonal price adjustment) represents the sale of a bundled product that includes, but is not limited to, energy, capacity and ancillary services. Furthermore, as a supplier of a portion of a utility's load, Midwest Generation will incur charges from PJM as a load serving entity. For these reasons, the average price per MWh under a load requirements services contract is not comparable to the sale of power under an energy only contract. The average price per MWh under a load requirements services contract represents the sale of the bundled product based on an estimated customer load profile.

The load requirements services contracts set forth in the table above are with Commonwealth Edison. Commonwealth Edison has stated that it would face possible bankruptcy if an electric rate freeze, which expired January 1, 2007, was re-introduced through legislation. On January 7, 2007, the Illinois House of Representatives voted to extend the rate freeze by three years, but the bill was not acted on by the State Senate before the Legislature adjourned its 2005-2006 session. It is possible that the issue will be revisited in the new 2007-2008 session, which convened on January 10, 2007. In addition, the Illinois Attorney General and other parties have appeals pending before the Illinois Supreme Court pertaining to the Illinois Commerce Commission orders which authorized Commonwealth Edison and Ameren Corporation to procure power through a reverse auction process. EME is unable to predict the outcome of the appeals or whether legislation or other policy changes affecting utility rates or procurement practices will be enacted, and, if so, what effect these developments may have on Commonwealth Edison's performance under the load requirement services contracts.

Energy Price Risk Affecting Sales from the Homer City Facilities

All the energy and capacity from the Homer City facilities is sold under terms, including price and quantity, arranged by EMMT with customers through a combination of bilateral agreements (resulting from negotiations or from auctions), forward energy sales and spot market sales. Electric power generated at the Homer City facilities is generally sold into the PJM market. PJM has a short-term market, which establishes 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 New York Independent System Operator markets.

The following table depicts the average historical market prices for energy per MWh at the Homer City busbar and in PJM West Hub (EME Homer City's primary trading hub) during the past three years:

Historical Energy Prices[1]
24-Hour PJM

	Homer City Busbar			**PJM West Hub**		
	2006	2005	2004	**2006**	2005	2004
January	**$ 48.67**	$ 45.82	$ 51.12	**$ 54.57**	$ 49.53	$ 55.01
February	**49.54**	39.40	47.19	**56.39**	42.05	44.22
March	**53.26**	47.42	39.54	**58.30**	49.97	39.21
April	**48.50**	44.27	43.01	**49.92**	44.55	42.82
May	**44.71**	43.67	44.68	**48.55**	43.64	48.04
June	**38.78**	46.63	36.72	**45.78**	53.72	38.05
July	**53.68**	54.63	40.09	**63.47**	66.34	43.64
August	**58.60**	66.39	34.76	**76.57**	82.83	38.59
September	**33.26**	66.67	40.62	**34.40**	76.82	41.96
October	**37.42**	67.93	37.37	**39.65**	77.56	37.78
November	**40.13**	59.78	35.79	**44.83**	62.01	36.91
December	**35.29**	75.03	38.59	**40.53**	81.97	41.83
Yearly Average	**$ 45.15**	$ 54.80	$ 40.79	**$ 51.08**	$ 60.92	$ 42.34

(1) Energy prices were calculated at the Homer City busbar (delivery point) and PJM West Hub using historical hourly real-time prices provided on the PJM web-site.

Forward market prices at the PJM West Hub fluctuate as a result of a number of factors, including natural gas prices, transmission congestion, changes in market rules, electricity demand (which in turn is affected by weather, economic growth and other factors), plant outages in the region, and the amount of existing and planned power plant capacity. The actual spot prices for electricity delivered by the Homer City facilities into these markets may vary materially from the forward market prices set forth in the table below.

The following table sets forth the forward month-end market prices for energy per MWh for the calendar 2007 and 2008 "strips," which are defined as energy purchases for the entire calendar year, as quoted for sales into the PJM West Hub during 2006:

	24-Hour PJM West Hub Forward Energy Prices[1]	
	2007	2008
January 31, 2006	$70.89	$67.69
February 28, 2006	62.16	60.09
March 31, 2006	66.79	64.37
April 30, 2006	70.11	68.07
May 31, 2006	63.22	61.33
June 30, 2006	63.80	62.58
July 31, 2006	67.66	64.26
August 31, 2006	65.23	63.17
September 30, 2006	57.61	58.25
October 31, 2006	57.97	59.31
November 30, 2006	61.26	61.83
December 31, 2006	52.13	59.13

(1) Energy prices were determined by obtaining broker quotes and information from other public sources relating to the PJM West Hub delivery point. Forward prices at PJM West Hub are generally higher than the prices at the Homer City busbar.

The following table summarizes Homer City's hedge position at December 31, 2006:

	2007	2008	2009
MWh	7,590,000	7,232,000	2,048,000
Average price/MWh[1]	$ 64.35	$ 60.85	$ 71.05

[1] The above hedge positions include forward contracts for the sale of power during different periods of the year and the day. Market prices tend to be higher during on-peak periods during summer months, although there is significant variability of power prices during different periods of time. Accordingly, the above hedge position at December 31, 2006 is not directly comparable to the 24-hour PJM West Hub prices set forth above.

The average price/MWh for Homer City's hedge position is based on PJM West Hub. Energy prices at the Homer City busbar have been lower than energy prices at the PJM West Hub. See "— Basis Risk" below for a discussion of the difference.

Basis Risk

Sales made from the Illinois plants and the Homer City facilities in the real-time or day-ahead market receive the actual spot prices or day-ahead prices, as the case may be, at the busbars (delivery points) of the individual plants. In order to mitigate price risk from changes in spot prices at the individual plant busbars, EME may enter into cash settled futures contracts as well as forward contracts with counterparties for energy to be delivered in future periods. Currently, a liquid market for entering into these contracts at the individual plant busbars does not exist. A liquid market does exist for a settlement point at the PJM West Hub in the case of the Homer City facilities and for a settlement point at the Northern Illinois Hub in the case of the Illinois plants. EME's hedging activities use these settlement points (and, to a lesser extent, other similar trading hubs) to enter into hedging contracts. EME's revenue with respect to such forward contracts include:

- sales of actual generation in the amounts covered by the forward contracts with reference to PJM spot prices at the busbar of the plant involved, plus,
- sales to third parties at the price under such hedging contracts at designated settlement points (generally the PJM West Hub for the Homer City facilities and the Northern Illinois Hub for the Illinois plants) less the cost of power at spot prices at the same designated settlement points.

Under PJM's market design, locational marginal pricing, which establishes market prices at specific locations throughout PJM by considering factors including generator bids, load requirements, transmission congestion and losses, can cause the price of a specific delivery point to be higher or lower relative to other locations depending on how the point is affected by transmission constraints. To the extent that, on the settlement date of a hedge contract, spot prices at the relevant busbar are lower than spot prices at the settlement point, the proceeds actually realized from the related hedge contract are effectively reduced by the difference. This is referred to as "basis risk." During 2006, transmission congestion in PJM has resulted in prices at the Homer City busbar being lower than those at the PJM West Hub by an average of 12%, compared to 10% during 2005 and 4% during 2004. The monthly average difference during 2006 ranged from 3% to 23%. In contrast to the Homer City facilities, during the past 12 months, the prices at the Northern Illinois Hub were substantially the same as those at the individual busbars of the Illinois plants.

By entering into cash settled futures contracts and forward contracts using the PJM West Hub and the Northern Illinois Hub (or other similar trading hubs) as settlement points, EME is exposed to basis risk as described above. In order to mitigate basis risk, EME has purchased 3.5 terawatt-hours of financial transmission rights and basis swaps in PJM for Homer City during the period January 1, 2007 through May 31, 2007, and may continue to purchase financial transmission rights and basis swaps in the future. A financial transmission right is a financial instrument that entitles the holder to receive the difference of actual spot prices for two delivery points in exchange for a fixed amount. Accordingly, EME's hedging activities include using financial transmission rights alone or in combination with forward contracts and basis swap contracts to manage basis risk.

Coal Price Risk

The Illinois plants and the Homer City facilities purchase coal primarily obtained from the Southern PRB of Wyoming and from mines located near the facilities in Pennsylvania, respectively. Coal purchases are made under a variety of supply agreements extending through 2010. The following table summarizes the amount of coal under contract at December 31, 2006 for the next four years.

	Amount of Coal Under Contract in Millions of Tons[1]			
	2007	2008	2009	2010
Illinois plants	17.2	5.8	5.8	5.8
Homer City facilities	5.2	2.1	0.8	—

(1) The amount of coal under contract in tons is calculated based on contracted tons and applying an 8.800 Btu equivalent for the Illinois plants and 13,000 Btu equivalent for the Homer City facilities.

In February 2007, Midwest Generation contracted for the purchase of additional coal in the amount of 9 million tons for 2008, 6 million tons for 2009 and 6 million tons for 2010.

EME is subject to price risk for purchases of coal that are not under contract. Prices of NAPP coal, which are related to the price of coal purchased for the Homer City facilities, decreased slightly in 2006 from 2005 year-end prices and increased considerably during 2005 and 2004. The price of NAPP coal (with 13,000 Btu per pound heat content and <3.0 pounds of SO_2 per million British Thermal units sulfur content) fluctuated between $37.50 per ton and $45.00 per ton during 2006, with a price of $43.00 per ton at December 15, 2006, as reported by the Energy Information Administration. The 2006 decrease in the NAPP coal price was largely due to the combined effects of mild weather, easing natural gas prices and improving eastern stockpiles. In 2005, the price of NAPP coal fluctuated between $44.00 per ton and $57.00 per ton, with a price of $45.00 per ton at December 30, 2005, as reported by the Energy Information Administration. In 2004, the price of NAPP coal increased to more than $60.00 per ton from below $40.00 per ton in January 2004. The 2005 overall increase in the NAPP coal price was largely attributed to greater demand from domestic power producers and increased international shipments of coal to Asia. Prices of PRB coal (with 8,800 Btu per pound heat content and 0.8 pounds of SO_2 per million British Thermal units sulfur content), which is purchased for the Illinois plants decreased during 2006 from 2005 year-end prices due to easing natural gas prices, fuel switching, lower prices for SO_2 allowances and improved inventory. Prices of PRB coal significantly increased in 2005 due to the curtailment of coal shipments during 2005 due to increased PRB coal demand from other regions (east), rail constraints, higher oil and natural gas prices and higher prices for SO_2 allowances. The price of PRB coal decreased from $20.66 per ton in January 2006 to $9.90 per ton at December 15, 2006, as reported by the Energy Information Administration, which compares to 2005 prices that ranged from $6.20 per ton to $18.48 per ton and 2004 prices which were generally below $7 per ton.

Based on EME's anticipated coal requirements in 2007 in excess of the amount under contract, EME expects that a 10% change in the price of coal at December 31, 2006 would increase or decrease pre-tax income in 2007 by approximately $2 million.

Emission Allowances Price Risk

The federal Acid Rain Program requires electric generating stations to hold SO_2 allowances, and Illinois and Pennsylvania regulations implemented the federal NOX SIP Call requirement. Under these programs, EME purchases (or sells) emission allowances based on the amounts required for actual generation in excess of (or less than) the amounts allocated under these programs. As part of the acquisition of the Illinois plants and the Homer City facilities, EME obtained the rights to the emission allowances that have been or are allocated to these plants.

The price of emission allowances, particularly SO_2 allowances issued through the federal Acid Rain Program, decreased in 2006 from 2005 year-end prices and increased substantially during 2005 and 2004. The average price of purchased SO_2 allowances was $664 per ton during 2006, $1,219 per ton during 2005 and $435 per ton during 2004. The decrease in the price of SO_2 allowances during 2006 from 2005 year-end prices has been attributed to a decline in natural gas prices and fuel switching from oil to gas. The 2005 increase in the price of SO_2 allowances had been attributed to reduced numbers of both allowance sellers and prior-year allowances. The price of SO_2 allowances, determined by obtaining broker quotes and information from other public sources, was $476 per ton as of January 31, 2007.

Based on EME's anticipated SO_2 emission allowances requirements in 2007, EME expects that a 10% change in the price of SO_2 emission allowances at December 31, 2006 would increase or decrease pre-tax income in 2007 by approximately $2 million. See "Other Developments—Environmental Matters" for a discussion of environmental regulations related to emissions.

MEHC's Accounting for Energy Contracts

EME uses a number of energy contracts to manage exposure from changes in the price of electricity, including forward sales and purchases of physical power and forward price swaps which settle only on a financial basis (including futures contracts). EME follows SFAS No. 133, and under this Standard these energy contracts are generally defined as derivative financial instruments. Importantly, SFAS No. 133 requires changes in the fair value of each derivative financial instrument to be recognized in earnings at the end of each accounting period unless the instrument qualifies for hedge accounting under the terms of SFAS No. 133. For derivatives that do qualify for cash flow hedge accounting, changes in their fair value are recognized in other comprehensive income until the hedged item settles and is recognized in earnings. However, the ineffective portion of a derivative that qualifies for cash flow hedge accounting is recognized currently in earnings. For further discussion of derivative financial instruments, see "Edison International (Consolidated)—Critical Accounting Estimates—Derivative Financial Instruments and Hedging Activities."

SFAS No. 133 affects the timing of income recognition, but has no effect on cash flow. To the extent that income varies under SFAS No. 133 from accrual accounting (i.e., revenue recognition based on settlement of transactions), EME records unrealized gains or losses. Unrealized SFAS No. 133 gains or losses result from:

- energy contracts that do not qualify for hedge accounting under SFAS No. 133 (which are sometimes referred to as economic hedges). Unrealized gains and losses include:
  - the change in fair value (sometimes called mark-to-market) of economic hedges that relate to subsequent periods, and
  - offsetting amounts to the realized gains and losses in the period nonqualifying hedges are settled.
- the ineffective portion of qualifying hedges which generally relate to changes in the expected basis between the sale point and the hedge point. Unrealized gains or losses include:
  - the current period ineffectiveness on the hedge program for subsequent periods. This occurs because the ineffective gains or losses are recorded in the current period, whereby the energy revenue related to generation being hedged will be recorded in the subsequent period along with the effective portion of the related hedge transaction, and
  - offsetting amounts to the realized ineffective gains and losses in the period cash flow hedges are settled.

EME classifies unrealized gains and losses from energy contracts as part of nonutility power generation revenue. The results of derivative activities are recorded as part of cash flows from operating activities in the consolidated statements of cash flows. The following table summarizes unrealized gains (losses) from nontrading activities for the three-year period ended December 31, 2006:

In millions Year Ended December 31,	2006	2005	2004
Nonqualifying hedges			
Illinois plants	$ 28	$ (17)	$ (4)
Homer City	2	(1)	1
Ineffective portion of cash flow hedges			
Illinois plants	2	(2)	—
Homer City	33	(40)	(14)
Total unrealized gains (losses)	$ 65	$ (60)	$ (17)

MEHC's Fair Value of Financial Instruments

Nontrading Derivative Financial Instruments

The following table summarizes the fair values for outstanding derivative financial instruments used in EME's continuing operations for purposes other than trading, by risk category:

In millions December 31,	2006	2005
Commodity price:		
Electricity	$ 184	$ (434)

In assessing the fair value of EME's nontrading 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 increase in the fair value of electricity contracts in 2006 as compared to 2005 is attributable to a decline in the average market prices for power as compared to contracted prices at December 31, 2006, which is the valuation date. A 10% change in the market price at December 31, 2006 would increase or decrease the fair value of outstanding derivative commodity price contracts by approximately $347 million. The following table summarizes the maturities and the related fair value, based on actively traded prices, of EME's commodity derivative assets and liabilities as of December 31, 2006:

In millions	Total Fair Value	Maturity <1 year	Maturity 1 to 3 years	Maturity 4 to 5 years	Maturity >5 years
Prices actively quoted	$ 184	$ 161	$ 23	$ —	$ —

Energy Trading Derivative Financial Instruments

The fair value of the commodity financial instruments related to energy trading activities as of December 31, 2006 and 2005, are set forth below:

	December 31, 2006		December 31, 2005	
In millions	Assets	Liabilities	Assets	Liabilities
Electricity	$ 313	$ 207	$ 127	$ 27
Other	5	—	1	—
Total	$ 318	$ 207	$ 128	$ 27

The change in the fair value of trading contracts for the year ended December 31, 2006 was as follows:

In millions	
Fair value of trading contracts at January 1, 2006	$ 101
Net gains from energy trading activities	137
Amount realized from energy trading activities	(131)
Other changes in fair value	4
Fair value of trading contracts at December 31, 2006	$ 111

A 10% change in the market price at December 31, 2006 would increase or decrease the fair value of trading contracts by approximately $2 million.

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, 2006:

In millions	Total Fair Value	Maturity <1 year	Maturity 1 to 3 years	Maturity 4 to 5 years	Maturity >5 years
Prices actively quoted	$ 26	$ 26	$ —	$ —	$ —
Prices provided by other external sources	(1)	(1)	—	—	—
Prices based on models and other valuation methods	86	4	13	18	51
Total	$ 111	$ 29	$ 13	$ 18	$ 51

MEHC's Credit Risk

In conducting EME's hedging and trading activities, EME contracts with a number of utilities, energy companies, financial institutions, and other companies, collectively referred to as counterparties. In the event a counterparty were to default on its trade obligation, EME would be exposed to the risk of possible loss associated with re-contracting the product at a price different from the original contracted price if the nonperforming counterparty were unable to pay the resulting liquidated damages owed to EME. Further, EME would be exposed to the risk of nopayment of accounts receivable accrued for products delivered prior to the time a counterparty defaulted.

To manage credit risk, EME looks at the risk of a potential default by counterparties. Credit risk is measured by the loss that would be incurred if counterparties failed to perform pursuant to the terms of their contractual obligations. EME measures, monitors and mitigates credit risk to the extent possible. To mitigate credit risk from counterparties, master netting agreements are used whenever possible and counterparties may be required to pledge collateral when deemed necessary. EME also takes other appropriate steps to limit or lower credit exposure. Processes have also been established to determine and monitor the creditworthiness of counterparties. EME manages the credit risk on 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. A risk management committee regularly reviews the credit quality of EME's counterparties. Despite this, there can be no assurance that these efforts will be wholly successful in mitigating credit risk or that collateral pledged will be adequate.

The credit risk exposure from counterparties of merchant energy activities (excluding load requirements services contracts) are measured as either: (i) the sum of 60 days of accounts receivable, current fair value of open positions, and a credit value at risk, or (ii) the sum of delivered and unpaid accounts receivable and the current fair value of open positions. EME's subsidiaries enter into master agreements and other arrangements in conducting hedging 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. At December 31, 2006, the amount of exposure as described above, broken down by the credit ratings of EME's counterparties, was as follows:

In millions	December 31, 2006
S&P Credit Rating:	
A or higher	$ 87
A−	6
BBB+	86
BBB	29
BBB−	3
Below investment grade	1
Total	$ 212

EME's plants owned by unconsolidated affiliates in which EME owns an interest sell power under power purchase agreements. Generally, each plant sells its output to one counterparty. Accordingly, a default by a counterparty under a power purchase agreement, including a default as a result of a bankruptcy, would likely have a material adverse effect on the operations of such power plant.

In addition, coal for the Illinois plants and the Homer City facilities is purchased from suppliers under contracts which may be for multiple years. A number of the coal suppliers to the Illinois plants and the Homer City facilities do not currently have an investment grade credit rating and, accordingly, EME may have limited recourse to collect damages in the event of default by a supplier. EME seeks to mitigate this risk through diversification of its coal suppliers and through guarantees and other collateral arrangements when available. Despite this, there can be no assurance that these efforts will be successful in mitigating credit risk from coal suppliers.

EME's merchant plants sell electric power generally into the PJM market by participating in PJM's capacity and energy markets or transact capacity and energy on a bilateral basis. Sales into PJM accounted for approximately 58% of EME's consolidated operating revenue for the year ended December 31, 2006. Moody's rates PJM's senior unsecured debt Aa3. PJM, an ISO with over 300 member companies, maintains its own credit risk policies and does not extend unsecured credit to noninvestment grade companies. Any losses due to a PJM member default are shared by all other members based upon a predetermined formula. At December 31, 2006, EME's account receivable due from PJM was $57 million.

Beginning in 2007, a significant amount of power from the Illinois plants will be sold to Commonwealth Edison under load requirements services contracts. See "— MEHC's Commodity Price Risk—Energy Price Risk Affecting Sales from the Illinois Plants" for further discussion.

MEHC's Interest Rate Risk

The fair market value of MEHC's parent only total long-term obligations was $933 million at December 31, 2006, compared to the carrying value of $795 million. A 10% increase or decrease in market interest rates at December 31, 2006 would result in a decrease or increase in the fair value of total long-term obligations by approximately $8 million.

Interest rate changes can affect earnings and the cost of capital for capital improvements or new investments in power projects. EME mitigates 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. Based on the amount of variable rate long-term debt for which EME has not entered into interest rate hedge agreements at December 31, 2006, a 100-basis-point change in interest rates at December 31, 2006 would increase or decrease 2007 income before taxes by approximately $4 million. The fair market values of long-term fixed interest rate obligations are subject to interest rate risk. The fair market value of MEHC's consolidated long-term obligations (including current portion) was $4.4 billion at

December 31, 2006, compared to the carrying value of $4.0 billion. A 10% increase in market interest rates at December 31, 2006 would result in a decrease in the fair value of MEHC's consolidated long-term obligations by approximately $138 million. A 10% decrease in market interest rates at December 31, 2006 would result in an increase in the fair value of MEHC's consolidated long-term obligations by approximately $155 million.

Edison Capital's Interest Rate Risk

The fair market value of Edison Capital's total long-term debt was $170 million at December 31, 2006, compared to a carrying value of $164 million. A 10% increase in market interest rates would have resulted in a $3 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 $4 million increase in the fair market value of Edison Capital's long-term debt.

Edison Capital's 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 in which it invests 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. 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, and regulatory actions affecting utilities purchasing power from the leased assets. 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 lead to a loss of some or all of Edison Capital's investment in that asset.

Edison Capital has a net leveraged lease investment, before deferred taxes, of $56 million in three aircraft leased to American Airlines. Although American Airlines has reported a profit in 2006, it has reported net losses for a number of years prior to 2006. A default in the leveraged lease by American Airlines could result in a loss of some or all of Edison Capital's lease investment. At December 31, 2006, American Airlines was current in its lease payments to Edison Capital.

Edison Capital also has a net leveraged lease investment, before deferred taxes, of $43 million in a 1,500-MW natural gas-fired cogeneration plant leased to Midland Cogen. During 2005, Midland Cogen wrote down the book value of its power plant as a result of substantial increases in long-term natural gas prices. A default of the lease could result in a loss of some or all of Edison Capital's lease investment. At December 31, 2006, Midland Cogen was current in its payments under the lease.

Edison Capital's Foreign Exchange Rate Risk

Edison Capital holds a minority interest as a limited partner in three separate funds that invest in infrastructure assets in Latin America, Asia and countries in Europe with emerging economies. Additionally, Edison Capital has invested in two companies, a cable television enterprise in Mexico and a natural gas pipeline company in Bolivia. As of December 31, 2006, Edison Capital had investments in Latin America, Asia and Emerging Europe of $25 million, $19 million and $20 million, respectively. Edison Capital, through these investments, is exposed to foreign exchange risk in the currency of the ultimate investment. Exposure in Emerging Europe is generally concentrated in the Euro. Investments in Asia are centered in China and South Korea. Investments made in Latin America are distributed among a number of South American countries, including Brazil, Mexico and Bolivia.

Edison Capital's cross-border leases are denominated in U.S. dollars and, therefore, are not exposed to foreign current rate risk.

EDISON INTERNATIONAL (PARENT)

EDISON INTERNATIONAL (PARENT): LIQUIDITY

The parent company's liquidity and its ability to pay interest and principal on debt, if any, operating expenses and dividends to common shareholders are affected by dividends and other distributions from subsidiaries, tax-allocation payments under its tax-allocation agreements with its subsidiaries, and access to capital markets or external financings. As of December 31, 2006, Edison International had no debt outstanding (excluding intercompany related debt).

Edison International (parent)'s cash requirements for the 12-month period following December 31, 2006 primarily consist of:

- Dividends to common shareholders. On February 22, 2007, the Board of Directors of Edison International declared a $0.29 per share quarterly dividend payable in April 2007;
- Intercompany related debt; and
- General and administrative expenses.

Edison International (parent) expects to meet its continuing obligations through cash and cash equivalents on hand, short-term borrowings, when necessary, and dividends from its subsidiaries. At December 31, 2006, Edison International (parent) had approximately $84 million of cash and cash equivalents on hand. As of December 31, 2006, Edison International (parent) had a $1 billion five-year senior unsecured credit facility which was entirely available for liquidity purposes. On February 23, 2007, Edison International amended its credit facility, increasing the amount of borrowing capacity to $1.5 billion and extending the maturity to February 2012. The ability of subsidiaries to make dividend payments to Edison International is dependent on various factors as described below.

SCE may pay dividends to Edison International subject to CPUC restrictions. The CPUC regulates SCE's capital structure by requiring that SCE maintain prescribed percentages of common equity, preferred equity and long-term debt in the utility's capital structure. SCE may not make any distributions to Edison International that would reduce the common equity component of SCE's capital structure below the authorized level on a 13-month weighted average basis. The CPUC also requires that SCE establish its dividend policy as though it were a comparable stand-alone utility company and give first priority to the capital requirements of the utility as necessary to meet its obligation to serve its customers. Other factors at SCE that affect the amount and timing of dividend payments by SCE to Edison International include, among other things, SCE's capital requirements, SCE's access to capital markets, payment of dividends on SCE's preferred and preference stock, and actions by the CPUC. During 2006, SCE made dividend payments to Edison International of $71 million on January 16, 2006, and $60 million on each of April 28, 2006, July 24, 2006, and October 26, 2006. On February 22, 2007, the Board of Directors of SCE declared a $25 million dividend to be paid to Edison International.

MEHC may not pay dividends unless it has an interest coverage ratio of at least 2.0 to 1. At December 31, 2006, its interest coverage ratio was 2.79 to 1. See "EMG: Liquidity—MEHC's Dividend Restrictions in Major Financings—Key Ratios of MEHC and EME's Principal Subsidiaries Affecting Dividends." In addition, MEHC's certificate of incorporation and senior secured note indenture contain restrictions on MEHC's ability to declare or pay dividends or distributions (other than dividends payable solely in MEHC's common stock). These restrictions require the unanimous approval of MEHC's Board of Directors, including its independent director, before it can declare or pay dividends or distributions, as long as any indebtedness is outstanding under the indenture. MEHC's ability to pay dividends is dependent on EME's ability to pay dividends to MEHC (parent). MEHC has not declared or made dividend payments to Edison International in 2006. EME and its subsidiaries have certain dividend restrictions as discussed in the "EMG Liquidity—MEHC's Dividend Restrictions in Major Financings" section.

Edison Capital's ability to make dividend payments is currently restricted by covenants in its financial instruments, which require Edison Capital, through a wholly owned subsidiary, to maintain a specified minimum net worth of $200 million. Edison Capital satisfied this minimum net worth requirement as of

December 31, 2006. During 2006, Edison Capital made dividend payments of $158 million to Edison International.

EDISON INTERNATIONAL (PARENT): OTHER DEVELOPMENTS

Holding Company Order Instituting Rulemaking

Edison International is a party to a CPUC holding company order instituting rulemaking. See "SCE: Regulatory Matters—Current Regulatory Developments—Holding Company Order Instituting Rulemaking" for a discussion of this matter.

Federal and State Income Taxes

Edison International received Revenue Agent Reports from the IRS in August 2002 and in January 2005 asserting deficiencies in federal corporate income taxes with respect to audits of its 1994 to 1996 and 1997 to 1999 tax years, respectively. Edison International has protested certain issues which are currently being addressed at the IRS administration appeals phase of the audit. See "Other Developments—Federal and State Income Taxes" for further discussion of these matters.

EDISON INTERNATIONAL (CONSOLIDATED)

The following sections of the MD&A are on a consolidated basis and should be read in conjunction with individual subsidiary discussion.

RESULTS OF OPERATIONS AND HISTORICAL CASH FLOW ANALYSIS

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

Results of Operations

The table below presents Edison International's earnings and earnings per common share for the years ended December 31, 2006, 2005 and 2004, and the relative contributions by its subsidiaries.

In millions, except per-share amounts	**Earnings (Loss)**			**Basic Earnings (Loss) per Share**		
Year Ended December 31,	**2006**	2005	2004	**2006**	2005	2004
Earnings (Loss) from Continuing Operations:						
SCE	**$ 776**	$ 725	$ 915	**$ 2.38**	$ 2.22	$ 2.81
EMG:						
MEHC	**244**	322	(666)	**0.75**	0.98	(2.05)
Edison Capital and other	**90**	92	60	**0.27**	0.29	0.18
EMG Total	**334**	414	(606)	**1.02**	1.27	(1.87)
Edison International (parent) and other	**(27)**	(31)	(83)	**(0.12)**	(0.11)	(0.25)
Edison International Consolidated Earnings from Continuing Operations	**1,083**	1,108	226	**3.28**	3.38	0.69
Earnings from Discontinued Operations	**97**	30	690	**0.30**	0.09	2.12
Cumulative Effect of Accounting Change	**1**	(1)	—	**—**	—	—
Edison International Consolidated	**$ 1,181**	$ 1,137	$ 916	**$ 3.58**	$ 3.47	$ 2.81

Earnings (Loss) from Continuing Operations

Edison International recorded earnings from continuing operations of $1.1 billion, or $3.28 per basic common share in 2006, compared to $1.1 billion, or $3.38 per basic common share in 2005.

2006 vs. 2005

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

EMG's earnings from continuing operations were $334 million in 2006, compared with earnings of $414 million in 2005. MEHC's earnings from continuing operations were $244 million in 2006, compared to $322 million in 2005. MEHC's 2006 decrease was primarily due to an after-tax charge of $90 million reflecting the early extinguishment of debt related to EME's debt refinancing in 2006, lower generation at Midwest Generation and lower energy trading income. These decreases were partially offset by the favorable SFAS No. 133 net impact, lower interest expense and a charge of $34 million recorded in 2005 related to the

March Point project. MEHC had SFAS No. 133 unrealized gains of $39 million in 2006, compared to unrealized losses of $35 million in 2005. Edison Capital and other's earnings were $90 million in 2006, compared with earnings of $92 million in 2005. Edison Capital's 2006 increase primarily reflects lower net corporate interest expense and a gain on the sale of an affordable housing project, partially offset by lower gains from its global infrastructure fund investments.

2005 vs. 2004

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

EMG's earnings from continuing operations were $414 million in 2005, compared with a loss of $606 million in 2004. MEHC's income from continuing operations was $322 million in 2005 compared to a loss of $666 million in 2004. MEHC's 2005 results include an impairment charge of $34 million related to the March Point project and a $15 million charge related to early debt retirements. MEHC's 2004 results included an after-tax charge of $590 million for the termination of the Collins Station lease, a net gain of $27 million on the sale of its interest in Four Star Oil and Gas and the Brooklyn Navy Yard projects and a charge of $18 million related to a peaker impairment. Excluding these charges, MEHC's earnings increased by $456 million over 2004 to $371 million. This increase was primarily due to higher wholesale energy margins mainly driven by higher prices, higher energy trading income and lower net interest expense. Earnings in 2005 for Edison Capital and other were $92 million, compared to $60 million in the same period last year. The increase primarily reflects higher income from Edison Capital's investment in the Emerging Europe Infrastructure Fund.

Excluding the 2004 charge related to the early debt retirements of $14 million, the loss for "Edison International (parent) and other" decreased by $38 million primarily due to lower net interest expense.

Operating Revenue

Electric Utility Revenue

The following table sets forth the major changes in electric utility revenue:

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

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

Total electric utility revenue increased $812 million in 2006, compared to 2005 (as shown in the table above). The increase resulting from rate changes was mainly due to rate increases implemented throughout 2006 (see "SCE: Regulatory Matters—Current Regulatory Developments—Impact of Regulatory Matters on Customer

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

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

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

Nonutility Power Generation Revenue

Nonutility power generation revenue decreased $20 million in 2006, and increased $609 million in 2005.

Nonutility power generation revenue from MEHC's Illinois plants decreased $30 million in 2006, and increased $371 million in 2005. The 2006 decrease was mainly due to lower energy revenue resulting from lower generation, partially offset by the impact of unrealized gains and losses related to certain hedge contracts. MEHC's Illinois plants recorded unrealized gains of $30 million in 2006, compared to unrealized losses of $19 million and $4 million in 2005 and 2004, respectively. Unrealized gains (losses) are primarily due to power contracts that did not qualify for hedge accounting treatment. These energy contracts were entered into to hedge the price risk related to projected sales of power. During 2005, power prices increased, resulting in mark-to-market losses. As these contracts were settled in 2006, the previous unrealized losses resulted in unrealized gains. See "EMG: Market Risk Exposures—MEHC's Commodity Price Risk" for more information regarding forward market prices. The 2005 increase was due to substantially higher energy revenue resulting from increased average realized energy prices, partially offset by lower capacity revenue resulting from the expiration of the power purchase agreement with Exelon Generation and higher unrealized losses related to hedge contracts (discussed above).

Nonutility power generation revenue from MEHC's Homer City facilities increased $50 million and $95 million in 2006 and 2005, respectively. The 2006 increase was primarily attributable to the net impact of unrealized gains and losses related to hedge contracts discussed below and higher average realized energy prices, partially offset by lower generation in 2006 due to an unplanned outage at Unit 3. Homer City is generally classified as a baseload plant, which means the amount of generation is largely based on the availability of the plant. Accordingly, the Unit 3 outage reduced the amount of generation during 2006. See "EMG: Other Developments—MEHC: Homer City Transformer Failure" for further discussion. Homer City recorded unrealized gains of $35 million in 2006, compared to unrealized losses of $41 million and $13 million in 2005 and 2004, respectively. Unrealized gains (losses) are primarily attributable to the ineffective portion of forward and futures contracts which are derivatives that qualify as cash flow hedges. The ineffective portion of hedge contracts at Homer City was primarily attributable to changes in the difference between energy prices at the PJM West Hub (the settlement point under forward contracts) and the energy prices at the Homer City busbar (the delivery point where power generated by the Homer City facilities is delivered into the transmission system). At December 31, 2006, unrealized losses of $11 million were recognized from the ineffective portion of cash flow hedges related to 2007. See "EMG: Market Risk Exposures—MEHC's Commodity Price Risk" for more information regarding forward market prices. The 2005 increase was primarily due to higher energy revenue resulting from higher wholesale energy prices, partially offset by higher unrealized losses related to hedge contracts (discussed above).

Revenue from energy trading activities at EMMT decreased $65 million in 2006 and increased $172 million in 2005. The 2006 decrease was primarily attributable to less congestion due in part to lower wholesale energy prices driven by lower natural gas prices. Volatile market conditions in 2005, driven by increased prices for natural gas and oil and warmer summer temperatures, created favorable conditions for EMMT's trading strategies in 2005 compared to 2004.

Due to higher electric demand resulting from warmer weather during the summer months and cold weather during the winter months, nonutility power generation revenue from MEHC's Illinois plants and Homer City facilities varies substantially. In addition, maintenance outages generally are scheduled during periods of lower projected electric demand (spring and fall) which reduces generation and increases major maintenance costs which are recorded as an expense when incurred. Seasonal fluctuations may also be affected by changes in market prices. See "EMG: Market Risk Exposures—MEHC's Commodity Price Risk—Energy Price Risk Affecting Sales from the Illinois Plants" and "— Energy Price Risk Affecting Sales from the Homer City Facilities" for further discussion regarding market prices.

Operating Expenses

Fuel Expense

In millions For the Year Ended December 31,	**2006**	2005	2004
SCE	**$ 1,112**	$ 1,193	$ 810
EMG – MEHC	**645**	617	619
Edison International Consolidated	**$ 1,757**	$ 1,810	$ 1,429

SCE's fuel expense decreased $81 million in 2006 and increased $383 million in 2005. The 2006 decrease was due to lower fuel expense of approximately $90 million at SCE's Mohave Generating Station resulting from the plant shutdown on December 31, 2005 (see "SCE: Regulatory Matters—Mohave Generating Station and Related Proceedings" for further discussion); lower fuel expense of $200 million related to SCE's consolidated VIEs, driven by lower natural gas prices; and lower nuclear fuel expense of $15 million resulting primarily from planned refueling and maintenance outages at SCE's San Onofre Unit 2 and Unit 3; partially offset by higher fuel expense of $240 million resulting from SCE's Mountainview plant which became operational in December 2005. The 2005 increase was primarily due to the consolidation of SCE's VIEs effective March 31, 2004 resulting in the recognition of fuel expense of $924 million in 2005 and $578 million in 2004.

MEHC's fuel expense increased $28 million in 2006 and decreased $2 million in 2005. The 2006 increase was mainly due to higher coal prices, partially offset by lower prices of SO_2 emission allowances at MEHC's Homer City facilities and lower generation. The 2005 decrease was mainly due to higher fuel expenses in 2004 during the period MEHC's Collins Station operated (operations ceased effective September 30, 2004), and the deconsolidation of MEHC's Doga project effective March 31, 2004. The 2005 decrease was almost entirely offset by an increase in fuel costs at MEHC's Illinois plants and Homer City facilities due to price escalation under coal and transportation agreements at MEHC's Illinois plants, and higher coal prices and higher priced SO_2 emission allowances at MEHC's Homer City facilities.

Purchased-Power Expense

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

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

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

Provisions for Regulatory Adjustment Clauses – Net

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

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

Other Operation and Maintenance Expense

In millions — For the Year Ended December 31,	**2006**	2005	2004
SCE	**$ 2,884**	$ 2,716	$ 2,634
EMG – MEHC	**825**	814	830
EMG – Edison Capital and other	**15**	51	34
Edison International (parent) and other	**38**	28	30
Edison International Consolidated	**$ 3,762**	$ 3,609	$ 3,528

SCE's other operation and maintenance expense increased $168 million in 2006 and $82 million in 2005. The 2006 increase was mainly due to higher generation-related costs of approximately $80 million resulting from the planned refueling and maintenance outages at SCE's San Onofre Unit 2 and Unit 3 and higher maintenance costs at Palo Verde, partially offset by lower costs at Mohave resulting from the plant ceasing operations on December 31, 2005; higher transmission and distribution maintenance cost of approximately $60 million; and increased operation and maintenance expense of $20 million at SCE's Mountainview plant as a result of the plant becoming operational at the end of 2005. Upon implementation of the 2006 GRC in May 2006, costs related to the Mohave shutdown, pensions, PBOPs, and the employee results sharing incentive plan are recovered through balancing account mechanisms. The 2005 increase was mainly due to an increase in reliability costs, demand-side management and energy efficiency costs, and benefit-related costs, partially offset by lower CEMA-related costs and generation-related costs. Reliability costs increased approximately $80 million, as compared to 2004, due to an increase in must-run units to improve the reliability of the California ISO systems operations (which are recovered through regulatory mechanisms approved by the FERC). Demand-side management and energy efficiency costs increased approximately $90 million (which are recovered through regulatory mechanisms approved by the CPUC). Benefit-related costs increased approximately $50 million in 2005, resulting from an increase in heath care costs and value of performance shares. The 2005 increase was partially offset by lower CEMA-related costs (primarily bark beetle infestation related costs) of approximately $95 million and a decrease in generation-related expenses of approximately $90 million, resulting from lower outage and refueling costs (in 2004, there was a scheduled major overhaul at SCE's Four Corners coal facility, as well as a refueling outage at SCE's San Onofre Unit 2). The 2005 variance also reflects an increase of approximately $35 million resulting from the consolidation of SCE's VIEs effective March 31, 2004.

MEHC's other operation and maintenance expense increased $11 million in 2006 and decreased $16 million in 2005. The 2006 increase was mainly due to higher plant overhaul costs at MEHC's Illinois plants. The 2005 decrease was mainly due to lower plant operating lease costs due to the termination of MEHC's Collins Station lease in April 2004, and a $56 million charge recorded in 2004 related to an estimate of possible future payments under a contract indemnity agreement related to asbestos claims with respect to activities at MEHC's Illinois plants prior to their acquisition in 1999 (see "Commitments, Guarantees and Indemnities—Guarantees and Indemnities—Indemnities Provided as Part of EME's Acquisition of the Illinois Plants" for further discussion). The 2005 decrease was partially offset by higher plant operation costs at MEHC's Illinois plants resulting from higher planned maintenance, and higher planned equipment maintenance costs in 2005 compared to 2004 and incurred costs in 2005 related to the replacement of the catalyst for the pollution-control equipment at MEHC's Homer City facilities.

Other operation and maintenance expense for Edison Capital and other decreased $36 million in 2006 mainly due to a reduction in Edison Capital's credit reserve requirements and the integration of Edison Capital's management and personnel with MEHC.

Asset Impairment and Loss on Lease Termination

Asset impairment and loss on lease termination in 2004 consisted of a $961 million loss recorded in 2004 related to the termination of MEHC's Collins Station lease and the transfer of ownership of the Collins Station to MEHC and the impairment of plant assets and related inventory reserves, and a $29 million charge related to the impairment of small peaking units in Illinois.

Depreciation, Decommissioning and Amortization Expense

In millions For the Year Ended December 31,	**2006**	2005	2004
SCE	**$ 1,026**	$ 915	$ 860
EMG – MEHC	**139**	123	142
EMG – Edison Capital and other	**16**	23	20
Edison International Consolidated	**$ 1,181**	$ 1,061	$ 1,022

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

Other Income and Deductions

Interest Income

In millions For the Year Ended December 31,	**2006**	2005	2004
SCE	**$ 51**	$ 38	$ 15
EMG – MEHC	**96**	60	8
EMG – Edison Capital and other	**19**	10	11
Edison International (parent) and other	**3**	4	12
Edison International Consolidated	**$ 169**	$ 112	$ 46

SCE's interest income increased $13 million in 2006 and $23 million in 2005. The 2006 and 2005 increases were mainly due to interest income from balancing accounts that were undercollected during both 2006 and 2005 (see interest expense below), and higher short-term interest rates in 2006, as compared to 2005.

MEHC's interest income increased $36 million in 2006 and $52 million in 2005. The 2006 increase was primarily due to higher interest income resulting from higher interest rates in 2006 compared to 2005. The 2005 increase was primarily due to higher interest income resulting from higher average cash balances in 2005 compared to 2004 due largely to cash proceeds received from the sale of MEHC's international operations.

Equity in Income from Partnerships and Unconsolidated Subsidiaries – Net

Equity in income from partnerships and unconsolidated subsidiaries – net decreased $57 million in 2006 and increased $70 million in 2005. The 2006 increase was mainly due to lower earnings of approximately

$50 million from Edison Capital's global infrastructure funds due to higher gains in 2005. The 2005 increase was mainly due to increased earnings of approximately $60 million from Edison Capital's global infrastructure funds and the write-off of approximately $20 million in 2004 of unamortized debt expenses resulting from the early termination of notes related to 8.6% and 7.875% cumulative quarterly income preferred securities issued through affiliates (EIX Trust I and II) partially offset by the effects of accounting for VIEs consolidated upon adoption of FIN 46(R) in the second quarter of 2004, resulting in a decrease of approximately $165 million in 2005 and $140 million in 2004. As a result, SCE now consolidates projects previously accounted for under the equity method by EME.

Other Nonoperating Income

In millions For the Year Ended December 31,	**2006**	2005	2004
SCE	**$ 85**	$ 127	$ 84
EMG – MEHC	**26**	9	51
EMG – Edison Capital and other	**22**	—	—
Edison International Consolidated	**$ 133**	$ 136	$ 135

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

MEHC's other nonoperating income increased $16 million in 2006 and decreased $42 million in 2005. The 2006 increase was mainly due to the recognition of an estimated business interruption insurance claim in the amount of $10 million related to MEHC's Homer City outage and an $8 million gain related to the receipt of shares from Mirant Corporation from settlement of a claim recorded during the first quarter of 2006. The 2005 decrease was mainly due to the recognition by MEHC of a pre-tax gain of $47 million on the sale of MEHC's interest in Four Star Oil & Gas recorded in January 2004, with no comparable gain in 2005.

Edison Capital and other's nonoperating income increased $23 million in 2006 mainly due to the recognition of a $19 million gain in 2006 on the sale of certain Edison Capital's investments, including an affordable housing project.

Interest Expense – Net of Amounts Capitalized

In millions For the Year Ended December 31,	**2006**	2005	2004
SCE	**$ (400)**	$ (360)	$ (409)
EMG – MEHC	**(387)**	(407)	(449)
EMG – Edison Capital and other	**(16)**	(23)	(29)
Edison International (parent) and other	**(4)**	(4)	(98)
Edison International Consolidated	**$ (807)**	$ (794)	$ (985)

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

MEHC's interest expense – net of amounts capitalized decreased $20 million in 2006 and $42 million in 2005. The 2006 decrease was mainly due to lower interest rates resulting from MEHC's refinancing in June 2006.

The 2005 decrease was mainly due to the repayment of MEHC (parent)'s $385 million term loan ($100 million of the term loan was repaid in July 2004 and the remaining $285 million of the term loan was repaid in January 2005), partially offset by higher interest expense at MEHC's Illinois plants, primarily attributable to a full year of interest expense in 2005 versus approximately eight months of interest expense in 2004 related to debt issued in April 2004 by Midwest Generation, which owns or leases the Illinois plants.

The decrease in interest expense – net of amounts capitalized related to Edison International and other in 2005 was due to the elimination of Edison International (parent)'s debt. Edison International (parent) has had no debt outstanding since the fourth quarter of 2004.

Impairment Loss on Equity Method Investment

During the third quarter of 2005, EME fully impaired its equity investment in the March Point project following an updated forecast of future project cash flows. The March Point project is a 140-MW natural gas-fired cogeneration facility located in Anacortes, Washington, in which a subsidiary of EME owns a 50% partnership interest. The March Point project sells electricity to Puget Sound Energy, Inc. under two power purchase agreements that expire in 2011 and sells steam to Equilon Enterprises, LLC (a subsidiary of Shell Oil) under a steam supply agreement that also expires in 2011. March Point purchases a portion of its fuel requirements under long-term contracts with the remaining requirements purchased at current market prices. March Point's power sales agreements do not provide for a price adjustment related to the project's fuel costs. During the first nine months of 2005, long-term natural gas prices increased substantially, thereby adversely affecting the future cash flows of the March Point project. As a result, management concluded that its investment was impaired and recorded a $55 million charge during the third quarter of 2005.

Loss on Early Extinguishment of Debt

Loss on early extinguishment of debt in 2006 primarily consisted of $146 million relating to the early repayment of substantially all of EME's 10% senior notes due August 15, 2008 and 9.875% senior notes due April 15, 2011. Loss on early extinguishment of debt of $25 million in 2005 primarily consisted of a $20 million loss related to the early repayment of the remaining balance of MEHC's $385 million term loan during the first quarter of 2005.

Income Tax Expense (Benefit)—Continuing Operations

In millions For the Year Ended December 31,	**2006**	2005	2004
SCE	**$ 438**	$ 292	$ 438
EMG – MEHC	**148**	169	(462)
EMG – Edison Capital and other	**6**	(7)	(14)
Edison International (parent) and other	**(10)**	3	(54)
Edison International Consolidated	**$ 582**	$ 457	$ (92)

Edison International's composite federal and state statutory tax rate was approximately 40% (net of the federal benefit for state income taxes) for all years presented. The effective tax rate of 35.0% realized in 2006 was primarily due to the effect on SCE of a settlement with the California Franchise Tax Board regarding a state apportionment issue (see "Other Developments—Federal and State Income Taxes") and the benefits received from low income housing and production tax credits at Edison Capital, partially offset by additional tax reserve accruals at SCE. The effective tax rate of 29.2% realized in 2005 was primarily due to the favorable resolution of the 1991 – 1993 IRS audit, as well as adjustments made to the tax reserve to reflect the issuance of new IRS regulations, and the favorable settlement of other federal and state tax audit issues at SCE and EME, and the benefits received from the low income housing and production tax credits at Edison Capital. The effective tax benefit rate of 68.7% realized in 2004 was primarily due to adjustments to tax liabilities relating to prior years at SCE and the benefits received from low income housing and production tax credits at Edison Capital, partially offset by property-related flow-through items and property-related adjustments at SCE.

At December 31, 2006, Edison International and its subsidiaries had California net operating loss carryforwards of $69 million with expiration dates beginning in 2011 and had state loss carryforwards for other states of $4 million with expiration dates beginning in 2022. At December 31, 2005, Edison International and its subsidiaries had federal tax credits of $31 million with $26 million to expire in 2024. At December 31, 2005, Edison International also had California net operating loss carryforwards of $128 million with expiration dates beginning in 2011 and had state loss carryforwards for other states of $6 million with expiration dates beginning in 2022.

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

Income from Discontinued Operations

Edison International's earnings from discontinued operations of $97 million in 2006 were mainly attributable to distributions from MEHC's Lakeland project and other adjustments related to the disposition of some of MEHC's international projects. Earnings from discontinued operations of $30 million during 2005 primarily reflect positive tax adjustments of $28 million resulting from the sales of international projects and $24 million in partial dividends from the Lakeland receivership and other items, partially offset by a charge of $25 million related to a tax indemnity on an international project sold in 2004. Earnings from discontinued operations during 2004 include gains of $533 million related to both the sale of MEHC's interests in Contact Energy and the sale of 11 of MEHC's 14 international projects and recognition of a tax benefit.

Cumulative Effect of Accounting Change – Net of Tax

Effective January 1, 2006, Edison International adopted SFAS No. 123(R) that requires the fair value accounting method for stock-based compensation. Implementation of SFAS No. 123(R) resulted in a $1 million, after-tax, cumulative-effect adjustment in the first quarter of 2006 (see "New Accounting Pronouncements" for further discussion).

Historical Cash Flow Analysis

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

Cash Flows from Operating Activities

Net cash provided (used) by operating activities:

In millions For the Year Ended December 31,	**2006**	2005	2004
Continuing operations	**$ 3,499**	$ 2,191	$ 1,600
Discontinued operations	**94**	22	(481)
	$ 3,593	$ 2,213	$ 1,119

Cash provided by operating activities from continuing operations increased $1.3 billion in 2006, compared to 2005. The 2006 increase was mainly due to an increase in cash collected from SCE's customers due to increased rates (see "SCE: Regulatory Matters—Current Regulatory Developments—Impact of Regulatory Matters on Customer Rates") and increased sales volume due to warmer weather in 2006, as compared to 2005, which contributed to higher balancing account overcollections in 2006, as compared to 2005. The 2006 increase was also attributable to a decrease of $748 million in required margin and collateral deposits in 2006 mainly for MEHC's hedging and trading activities, compared to an increase of $768 million in 2005. The change resulted from a decrease in forward market prices in 2006 from 2005 and settlement of hedge contracts during 2006. In addition, the 2006 change was also due to the timing of cash receipts and disbursements related to working capital items and higher income taxes paid in 2006, compared to 2005. The 2005 change in cash provided by operating activities from continuing operations was mainly due to an increase in income from continuing operations, and the results from the timing of cash receipts and disbursements related to working capital items.

Cash provided by operating activities from discontinued operations increased $72 million in 2006, compared to 2005 reflecting higher distributions received in 2006, compared to 2005, from MEHC's Lakeland power project. See "Discontinued Operations" for more information regarding these distributions. Cash used in operating activities from discontinued operations of $481 million in 2004 primarily reflects settlement of working capital items from the sale of MEHC's international operations.

Cash Flows from Financing Activities

Net cash used by financing activities:

In millions For the Year Ended December 31,	**2006**	2005	2004
Continuing operations	**$ (699)**	$ (1,234)	$ (1,258)
Discontinued operations	**—**	—	(144)
	$ (699)	$ (1,234)	$ (1,402)

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

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

- In January 2006, SCE issued $500 million of first and refunding mortgage bonds which consisted of $350 million of 5.625% bonds due in 2036 and $150 million of floating rate bonds due in 2009. The proceeds from this issuance were used to redeem $150 million of variable rate first and refunding mortgage bonds due in January 2006 and $200 million of its 6.375% first and refunding mortgage bonds due in January 2006.
- In January 2006, SCE issued two million shares of 6% Series C preference stock (noncumulative, $100 liquidation value) and received net proceeds of $197 million.
- In April 2006, SCE issued $331 million of pollution control bonds which consisted of $196 million of 4.10% bonds due in 2028 and $135 million of 4.25% bonds due in 2033. The proceeds from this issuance were used to redeem a total of $331 million of pollution control bonds due in 2008. This transaction was treated as a noncash financing activity.
- In June 2006, EME issued $1 billion of senior notes. The proceeds from this issuance were mostly used to repay $965 million of EME's outstanding senior notes and $139 million paid for tender premiums and related fees.
- In December 2006, SCE issued $400 million of 5.55% first and refunding mortgage bonds due in 2037. The proceeds from this issuance were used for general corporate purposes.
- During 2006, Midwest Generation had net repayments of $170 million under its credit facility.
- Financing activities in 2006 also included dividend payments of $352 million paid by Edison International to its shareholders.

Financing activities in 2005 included activities related to the rebalancing of SCE's capital structure and the reduction of debt at MEHC.

- In January 2005, SCE issued $650 million of first and refunding mortgage bonds which consisted of $400 million of 5% bonds due in 2016 and $250 million of 5.55% bonds due in 2036. The proceeds from this issuance were used to redeem the remaining $50,000 of its 8% first and refunding mortgage bonds due February 2007 (Series 2003A) and $650 million of the $966 million 8% first and refunding mortgage bonds due February 2007 (Series 2003B).
- In January 2005, MEHC repaid the remaining $285 million of its term loan.
- In January 2005, MEHC repaid $150 million of its junior subordinated debentures.

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

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

- *In April 2005, MEHC repaid $302 million related to Midwest Generation's existing term loan.*

- In June 2005, SCE issued $350 million of 5.35% first and refunding mortgage bonds due in 2035 (Series 2005E). A portion of the proceeds from this issuance were used to redeem $316 million of its 8% first and refunding mortgage bonds due in 2007 (Series 2003B).

- In August 2005, SCE issued $249 million of variable rate pollution control bonds due in 2035. The proceeds from this issuance were used to redeem $29 million of 6.90% pollution control bonds due in 2017, $30 million of 6.0% pollution control bonds due in 2027 and $190 million of 6.40% pollution control bonds due in 2024. This transaction was treated as a noncash financing activity.

- Financing activities in 2005 also include dividend payments of $326 million paid by Edison International to its shareholders.

Financing activities in 2004 included activities mainly related to activities at SCE and MEHC.

- In January 2004, SCE issued a total of $975 million of bonds, consisting of $300 million of 5% bonds due in 2014, $525 million of 6% bonds due in 2034, and $150 million of floating rate bonds due in 2006. The proceeds from the issuances were used to call at par $300 million of 7.25% first and refunding mortgage bonds due March 2026, $225 million of 7.125% first and refunding mortgage bonds due July 2025, $200 million of 6.9% first and refunding mortgage bonds due October 2018, and $100 million of junior subordinated deferrable interest debentures due June 2044.

- *In March 2004, SCE remarketed approximately $550 million of pollution control bonds with varying* maturity dates ranging from 2008 to 2040. Approximately $354 million of these pollution control bonds had been held by SCE since 2001 and the remaining $196 million were purchased and reoffered in 2004.

- In March 2004, SCE issued $300 million of 4.65% first and refunding mortgage bonds due in 2015 and $350 million of 5.75% first and refunding mortgage bonds due in 2035. A portion of the proceeds from the March 2004 first and refunding mortgage bond issuances were used to fund the acquisition and construction of the Mountainview plant.

- In April 2004, MEHC issued $1 billion secured notes and $700 million term loan facility obtained by Midwest Generation.

- In April 2004, MEHC repaid $693 million related to Edison Mission Midwest Holdings' credit facility.

- In April 2004, MEHC repaid $28 million related to EME's Coal and Capex facility.

- *In July 2004, MEHC repaid $100 million related to MEHC's $385 million term loan.*

- In September 2004, Edison International (parent) repaid its $618 million 6⅞% notes due September 2004 and in November and December 2004 repaid its $825 million of notes related to 8.6% and 7.875% cumulative quarterly income preferred securities issued through affiliates (EIX Trust I and II).

- In October and December 2004, MEHC repaid the $800 million secured loan at EME's subsidiary, Mission Energy Holdings International, Inc.

- In December 2004, SCE issued $150 million of floating rate first and refunding mortgage bonds due in 2007. The proceeds from this issuance were used for general corporate purposes.

- During 2004, SCE repaid $125 million of its 5.875% bonds due in September 2004, and the $200 million outstanding balance of its credit facility.
- During 2004, Edison Capital made net payments of $119 million on long-term debt.
- Financing activities in 2004 also included dividend payments of $261 million paid by Edison International to its shareholders.

Cash used in financing activities from discontinued operations in 2004 primarily reflects repayment of debt and dividends to minority shareholders.

Cash Flows from Investing Activities

Net cash provided (used) by investing activities:

In millions For the Year Ended December 31,	**2006**	2005	2004
Continuing operations	**$ (2,992)**	$ (1,780)	$ 640
Discontinued operations	**—**	5	58
	$ (2,992)	$ (1,775)	$ 698

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

Investing activities in 2006 reflect $2.2 billion in capital expenditures at SCE, primarily for transmission and distribution assets, including approximately $81 million for nuclear fuel acquisitions and $13 million related to the Mountainview plant, and $310 million in capital expenditures at MEHC. In addition, investing activities include net purchases of marketable securities of $375 million at MEHC and $18 million paid by EME toward the purchase price of the Wildorado wind project.

Investing activities in 2005 reflect $1.8 billion in capital expenditures at SCE, primarily for transmission and distribution assets, including approximately $59 million for nuclear fuel acquisitions and approximately $166 million related to the Mountainview plant, and $57 million in capital expenditures at MEHC. Investing activities also include $124 million in proceeds received in 2005 from the sale of EME's 25% investment in the Tri Energy project and EME's 50% investment in the Caliraya-Botocan-Kalayaan project, $154 million paid towards the purchase price for EME's San Juan Mesa project in December 2005 and net purchases of marketable securities of $43 million at MEHC.

Investing activities in 2004 reflect $1.7 billion in capital expenditures at SCE, primarily for transmission and distribution assets, including approximately $70 million for nuclear fuel acquisitions, and $55 million in capital expenditures at EME. In addition, investing activities include $285 million of acquisition costs related to the Mountainview plant at SCE, $118 million in proceeds received in 2004 at EME from the sale of 100% of EME's stock of Edison Mission Energy Oil & Gas and the sale of EME's 50% partnership interest in the Brooklyn Navy Yard project, $2.7 billion in proceeds received in 2004 at EME from the sale of its international projects and net purchases of marketable securities of $120 million at MEHC.

DISCONTINUED OPERATIONS

On February 3, 2005, EME sold its 25% equity interest in the Tri Energy project, pursuant to a purchase agreement dated December 15, 2004, to IPM, for approximately $20 million. The sale of this investment had no significant effect on net income in the first quarter of 2005.

On January 10, 2005, EME sold its 50% equity interest in the Caliraya-Botocan-Kalayaan project to Corporacion IMPSA S.A., pursuant to a purchase agreement dated November 5, 2004. Proceeds from the sale were approximately $104 million. EME recorded a pre-tax gain on the sale of approximately $9 million during the first quarter of 2005.

On December 16, 2004, EME sold the stock and related assets of MECIBV to IPM, pursuant to a purchase agreement dated July 29, 2004. The purchase agreement was entered into following a competitive bidding process. The sale of MECIBV included the sale of EME's interests in ten electric power generating projects or companies located in Europe, Asia, Australia, and Puerto Rico. Consideration from the sale of MECIBV and related assets was $2.0 billion.

On September 30, 2004, EME sold its 51% interest in Contact Energy to Origin Energy New Zealand Limited pursuant to a purchase agreement dated July 20, 2004. The purchase agreement was entered into following a competitive bidding process. Consideration for the sale was NZ$1.6 billion (approximately $1.1 billion) which includes NZ$535 million of debt assumed by the purchaser.

EME previously owned a 220-MW power plant located in the United Kingdom, referred to as the Lakeland project. An administrative receiver was appointed in 2002 as a result of a default by its counterparty, a subsidiary of TXU Europe Group plc. Following a claim for termination of the power sales agreement, the Lakeland project received a settlement of £116 million (approximately $217 million). EME is entitled to receive the remaining amount of the settlement after payment of creditor claims. As creditor claims have been settled, EME has received to date payments of £13 million (approximately $24 million) in 2005, £72 million (approximately $125 million) in 2006 and £4 million (approximately $8 million) in January 2007. The after-tax income attributable to the Lakeland project was $85 million and $24 million for 2006 and 2005, respectively, and none in 2004. Beginning in 2002, EME reported the Lakeland project as discontinued operations and accounts for its ownership of Lakeland Power on the cost method (earnings are recognized as cash is distributed from the project).

For all years presented, the results of EME's international projects, discussed above, have been accounted for as discontinued operations on the consolidated financial statements in accordance with SFAS No. 144.

There was no revenue from discontinued operations in 2006 or 2005. Revenue from discontinued operations was $1.3 billion in 2004. The pre-tax earnings (loss) from discontinued operations were $118 million in 2006, $(20) million in 2005 and $737 million in 2004. The pre-tax loss from discontinued operations in 2005 included a $9 million gain on sale before taxes. The pre-tax earnings from discontinued operations in 2004 included a $532 million gain on sale before taxes related to EME's international power generation portfolio.

During the fourth quarter of 2006, EME recorded a tax benefit adjustment of $22 million, which resulted from resolution of a tax uncertainty pertaining to the ownership interest in a foreign project. EME's payment of $34 million during the second quarter of 2006 related to an indemnity to IPM for matters arising out of the exercise by one of its project partners of a purported right of first refusal resulted in a $3 million additional loss recorded in 2006. During the fourth quarter of 2005, EME recorded an after-tax charge of $25 million related to a tax indemnity for a project sold to IPM in December 2004. This charge related to an adverse tax court ruling in Spain, which the local company appealed. During the third quarter of 2005, EME recorded tax benefit adjustments of $28 million, which resulted from completion of the 2004 federal and California income tax returns and quarterly review of tax accruals. Most of the tax adjustments are related to the sale of the international projects in December 2004. These adjustments (benefits) are included in income from discontinued operations – net of tax on the consolidated statements of income.

There were no assets or liabilities of discontinued operations at December 31, 2006. At December 31, 2005, the assets and liabilities of discontinued operations were segregated on the consolidated balance sheet and consisted of current assets of $2 million, other long-term assets of $9 million and long-term liabilities of $14 million.

ACQUISITIONS AND DISPOSITIONS

Acquisitions

On January 5, 2006, EME completed a transaction with Cielo Wildorado, G.P., LLC and Cielo Capital, L.P. to acquire a 99.9% interest in the Wildorado Wind Project, which owns a 161-MW wind farm located in the panhandle of northern Texas, referred to as the Wildorado wind project. The acquisition included all development rights, title and interest held by Cielo in the Wildorado wind project, except for a small minority stake in the project retained by Cielo. The total purchase price was $29 million. As of December 31, 2006, a cash payment of $18 million had been made towards the purchase price. This project started construction in April 2006 and is scheduled for completion in April 2007, with total construction costs, excluding capitalized interest, estimated to be $270 million. The acquisition was accounted for utilizing the purchase method. The fair value of the Wildorado wind project was equal to the purchase price and as a result, the total purchase price was allocated to nonutility property in Edison International's consolidated balance sheet.

On December 27, 2005, EME completed a transaction with Padoma Project Holdings, LLC to acquire a 100% interest in the San Juan Mesa Wind Project, which owns a 120 MW wind power generation facility located in New Mexico, referred to as the San Juan Mesa wind project. The total purchase price was approximately $157 million. The acquisition was funded with cash. The acquisition was accounted for utilizing the purchase method. The fair value of the San Juan Mesa wind project was equal to the purchase price and as a result, the entire purchase price was allocated to nonutility property in Edison International's consolidated balance sheet. Edison International's consolidated statement of income reflected the operations of the San Juan Mesa project beginning January 1, 2006. The pro forma effects of the San Juan Mesa wind project acquisition on Edison International's consolidated financial statements were not material.

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

Dispositions

On March 7, 2006, EME completed the sale of a 25% ownership interest in the San Juan Mesa wind project to Citi Renewable Investments I LLC, a wholly owned subsidiary of Citicorp North America, Inc. Proceeds from the sale were $43 million. EME recorded a pre-tax gain on the sale of approximately $4 million during the first quarter of 2006.

In March 2004, EME completed the sale of its 50% partnership interest in Brooklyn Navy Yard for a sales price of approximately $42 million. EME recorded an impairment charge of $53 million during the fourth quarter of 2003 related to the planned disposition of this investment and a pre-tax loss of approximately $4 million during the first quarter of 2004 due to changes in the terms of the sale.

In January 2004, EME completed the sale of 100% of its stock of Edison Mission Energy Oil & Gas, which in turn held minority interests in Four Star Oil & Gas. Proceeds from the sale were approximately $100 million. EME recorded a pre-tax gain on the sale of approximately $47 million during the first quarter of 2004.

CRITICAL ACCOUNTING ESTIMATES

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. Many of the critical accounting estimates discussed below generally do not impact SCE's earnings since SCE applies accounting principles for rate-regulated enterprises. However, these critical accounting estimates may impact amounts reported on the consolidated balance sheets.

Rate Regulated Enterprises

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

Derivative Financial Instruments and Hedging Activities

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

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

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

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

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

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

EME uses derivative financial instruments for hedging activities and trading purposes. Derivative financial instruments are mainly utilized to manage exposure from changes in electricity and fuel prices, and interest rates.

Derivative financial instruments used for trading purposes include forwards, futures, options, swaps and other financial instruments with third parties. EME records derivative financial instruments used for trading at fair value. 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 considering the time value of money, volatility of the underlying commodity, and other factors as determined by EME. Resulting gains and losses are recognized in nonutility power generation revenue in the accompanying consolidated statements of income in the period of change. Derivative assets include 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. Derivative liabilities include open financial positions related to derivative financial instruments, including cash flow hedges that are "out-of-the-money."

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

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.

The SFAS No. 109, Accounting 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 jurisdiction in which it operates. This process involves estimating actual current tax expense together with assessing temporary differences resulting from differing treatment of items, such as depreciation, for tax and accounting purposes. These differences result in deferred tax assets and liabilities, which are included within Edison International's consolidated balance sheet. Edison International takes certain tax positions it believes are applied in accordance with tax laws. The application of these positions is subject to interpretation and audit by the IRS. As further described in "Other Developments—Federal and State Income Taxes," the IRS has raised issues in the audit of Edison International's tax returns with respect to certain leveraged leases at Edison Capital.

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

Off-Balance Sheet Financing

EME has entered into sale-leaseback transactions related to the Powerton and Joliet plants in Illinois and the Homer City facilities in Pennsylvania. (See "Off-Balance Sheet Transactions—MEHC's Off-Balance Sheet Transactions—Sale-Leaseback Transactions.") Each of these transactions was completed and accounted for in accordance with SFAS No. 98, which requires, among other things, that all 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. The sale-leaseback transactions of these power plants were complex matters that involved management judgment to determine compliance with SFAS No. 98, 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 because 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 "MEHC's 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 nonrecourse and is not recorded on Edison International's balance sheet in accordance with SFAS No. 13, Accounting for Leases.

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 Principles Board Opinion No. 18, The Equity Method of Accounting for Investments in Common Stock. 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."

Asset Impairment

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

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

During 2005 and 2004, MEHC recorded impairment charges of $55 million and $35 million, respectively, related to specific assets included in continuing operations. See "Results of Operations and Historical Cash Flow Analysis—Results of Operations—Operating Expenses—Asset Impairment and Loss on Lease Termination."

Nuclear Decommissioning

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

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

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

Pensions and Postretirement Benefits Other than Pensions

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

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

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

SCE accounts for about 93% of Edison International's total pension obligation, and 97% of its assets held in trusts, at December 31, 2006. SCE records pension expense equal to the amount funded to the trusts, as calculated using an actuarial method required for rate-making purposes, in which the impact of market volatility on plan assets is recognized in earnings on a more gradual basis. Any difference between pension expense calculated in accordance with rate-making methods and pension expense calculated in accordance with SFAS No. 71 is accumulated as a regulatory asset or liability, and will, over time, be recovered from or returned to customers. As of December 31, 2006, this cumulative difference amounted to a regulatory liability of $78 million, meaning that the rate-making method has recognized $78 million more in expense than the accounting method since implementation of SFAS No. 87, Employers' Accounting for Pensions, in 1987.

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

At December 31, 2006, Edison International's PBOP plans had a $2.3 billion benefit obligation. Total expense for these plans was $76 million for 2006. The health care cost trend rate is 9.25% for 2007, gradually declining to 5.0% for 2011 and beyond. Increasing the health care cost trend rate by one percentage point would increase the accumulated obligation as of December 31, 2006 by $281 million and annual aggregate service and interest costs by $19 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated obligation as of December 31, 2006 by $250 million and annual aggregate service and interest costs by $17 million.

NEW ACCOUNTING PRONOUNCEMENTS

Accounting Pronouncements Adopted

SFAS No. 123(R) requires companies to use the fair value accounting method for stock-based compensation. Edison International implemented SFAS No. 123(R) in the first quarter of 2006 and applied the modified prospective transition method. Under the modified prospective method, SFAS No. 123(R) was applied effective January 1, 2006 to the unvested portion of awards previously granted and will be applied to all prospective awards. Prior financial statements were not restated under this method. SFAS No. 123(R) resulted in the recognition of expense for all stock-based compensation awards. In addition, Edison International elected to calculate the pool of windfall tax benefits as of the adoption of SFAS No. 123(R) based on the method (also known as the short-cut method) proposed in FSP FAS 123(R)-3, Transition Election to Accounting for the Tax Effects of Share-Based Payment Awards. Prior to January 1, 2006, Edison International used the intrinsic value method of accounting, which resulted in no recognition of expense for its stock options. Prior to adoption of SFAS No. 123(R), Edison International presented all tax benefits of deductions resulting from the exercise of stock options as a component of operating cash flows under the caption "Other liabilities" in the consolidated statements of cash flows. SFAS No. 123(R) requires the cash flows resulting from the tax benefits that occur from estimated tax deductions in excess of the compensation cost recognized for those options (excess tax benefits) to be classified as financing cash flows. The $27 million excess tax benefit is classified as a financing cash inflow in 2006. Due to the adoption of SFAS No. 123(R), Edison International recorded a cumulative effect adjustment that increased net income by approximately $1 million, net of tax, in the first quarter of 2006, mainly to reflect the change in the valuation method for performance shares classified as liability awards and the use of forfeiture estimates.

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

In September 2006, the FASB issued SFAS No. 158, which amends the accounting by employers for defined benefit pension plans and PBOPs. SFAS No. 158 requires companies to recognize the overfunded or underfunded status of defined benefit pension and other postretirement plans as assets and liabilities in the balance sheet; the assets and/or liabilities are offset through other comprehensive income (loss). Edison International adopted SFAS No. 158 as of December 31, 2006. Edison International recorded regulatory assets and liabilities instead of charges and credits to other comprehensive income (loss) for its postretirement benefit plans that are recoverable in utility rates, in accordance with SFAS No. 71. SFAS No. 158 also requires companies to align the measurement dates for their plans to their fiscal year-ends; Edison International already has a fiscal year-end measurement date for all of its postretirement plans. Upon adoption, Edison International recorded additional postretirement benefit assets of $145 million, additional postretirement liabilities of $333 million (including $30 million classified as current), additional regulatory assets of $303 million, regulatory liabilities of $145 million, and a reduction to accumulated other comprehensive income (loss) (a component of shareholders' equity) of $18 million, net of tax.

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

Accounting Pronouncements Not Yet Adopted

In July 2006, the FASB issued an interpretation (FIN 48) clarifying the accounting for uncertainty in income taxes. An enterprise would be required to recognize, in its financial statements, the best estimate of the impact of a tax position by determining if the weight of the available evidence indicates it is more likely than not, based solely on the technical merits, that the position will be sustained on audit. Edison International will adopt FIN 48 in the first quarter of 2007. Edison International is currently assessing the impact of FIN 48 on its financial statements. Based on the current status of discussions with tax authorities related to open tax years under audit and other information currently available, implementation of FIN 48 is expected to result in a cumulative-effect adjustment increasing retained earnings in a range of approximately $250 million to $300 million upon adoption. The estimated range is subject to final completion of Edison International's analysis and assessment of each uncertain tax position. Edison International will continue to monitor and assess new income tax developments including the IRS' challenge of the sale/leaseback and lease/leaseback transactions discussed in "Other Developments—Federal and State Income Taxes."

In July 2006, the FASB issued an FSP on accounting for a change or projected change in the timing of cash flows relating to income taxes generated by a leveraged lease transaction (FSP FAS 13-2). The effective date is January 1, 2007. As discussed under "Other Developments—Federal and State Income Taxes," the deferral of income taxes associated with Edison Capital's cross-border, leveraged leases has been challenged by the IRS. If it becomes more likely than not that Edison International would accelerate the payment of deferred taxes for these leases, FSP FAS 13-2 requires the change in the timing of cash flows to trigger a recalculation of the income allocated over the life of the lease, with the cumulative effect of the change recognized immediately. This could result in a material charge against earnings, although future income would be expected to increase over the remaining terms of the affected leases.

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

COMMITMENTS, GUARANTEES AND INDEMNITIES

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

In millions	2007	2008	2009	2010	2011	Thereafter
Long-term debt maturities and interest[1]	$ 1,128	$ 1,474	$ 1,251	$ 759	$ 759	$ 11,791
Fuel supply contract payments	440	224	140	115	63	269
Gas and coal transportation payments	228	92	83	84	8	52
Purchased-power capacity payments	481	255	144	134	112	642
Operating lease obligations	978	951	885	831	598	4,411
Capital lease obligations	3	3	3	4	—	—
Turbine commitments	463	26	—	—	—	—
Capital improvements	186	—	—	—	—	—
Other commitments	16	16	16	15	6	31
Employee benefit plans contributions[2]	108	—	—	—	—	—
Total	$ 4,031	$ 3,041	$ 2,522	$ 1,942	$ 1,546	$ 17,196

(1) Amount includes scheduled principal payments for debt outstanding as of December 31, 2006, assuming long-term debt is held to maturity, except for EME's Midwest Generation senior secured notes which are assumed to be held until 2014, and related forecast interest payments over the applicable period of the debt.

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

Fuel Supply Contracts

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

At December 31, 2006, Midwest Generation and EME Homer City had contractual commitments to purchase coal with various third-party suppliers. The remaining contracts' lengths range from less than one year to six years. The minimum commitments are based on the contract provisions, which consist of fixed prices, subject to adjustment clauses. For further discussion, see "EMG: Market Risk Exposures—MEHC's Commodity Price Risk—Coal Price Risk."

In February 2007, EME contracted for the purchase of additional coal in the amount of nine million tons for 2008, six million tons for 2009 and six million tons for 2010.

Gas and Coal Transportation

At December 31, 2006, EME had a contractual commitment to transport natural gas. EME is committed to pay its share of fixed monthly capacity charges under its gas transportation agreement, which has a remaining contract length of 11 years.

At December 31, 2006, EME's subsidiaries had contractual commitments for the transport of coal to their respective facilities, with remaining contract lengths that range from one year to five years. Midwest Generation's primary contract is with Union Pacific Railroad (and various delivery carriers) which extends through 2011. Midwest Generation commitments under this agreement are based on actual coal purchases from the PRB. Accordingly, Midwest Generation's contractual obligations for transportation are based on coal volumes set forth in their fuel supply contracts. EME Homer City commitments under its agreements are based on the contract provisions, which consist of fixed prices, subject to adjustment clauses. Although trucking remains the predominant mode of transportation for coal shipments to the Homer City facilities, rail transportation is expected to increase in 2007 as EME Homer City diversifies its alternative modes of transporting coal to the plant site.

Power-Purchase Contracts

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

Operating and Capital Leases

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

At December 31, 2006, minimum operating lease payments were primarily related to long-term leases for the Powerton and Joliet Stations and the Homer City facilities. During 2000, EME entered into sale-leaseback transactions for two power facilities, the Powerton and Joliet coal-fired stations located in Illinois, with third-party lessors. During the fourth quarter of 2001, EME entered into a sale-leaseback transaction for the Homer City coal-fired facilities located in Pennsylvania, with third-party lessors. Total minimum lease payments during the next five years are $336 million in 2007, $337 million in 2008, $336 million in 2009, $325 million in 2010, $312 million in 2011, and the minimum lease payments due after 2011 are $2.6 billion. For further discussion, see "Off-Balance Sheet Transactions—MEHC's Off-Balance Sheet Transactions—Sale-Leaseback Transactions."

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

Turbine Commitments

At December 31, 2006, EME had entered into agreements with vendors securing 255 wind turbines (487 MW) with remaining commitments of $387 million in 2007 and $23 million in 2008. In addition, EME had entered into an agreement for the purchase of five gas turbines and related equipment for an aggregate purchase price of approximately $140 million with remaining commitments of $76 million in 2007 and $3 million in 2008. In February 2007, EME was advised that it was an unsuccessful bidder in the request for offers conducted by SCE for the supply of generation capacity. EME plans to use the turbines which it had purchased and reserved for this bid for other generation supply opportunities.

Capital Improvements

At December 31, 2006, EME's subsidiaries had firm commitments for capital and construction expenditures. The majority of these expenditures relate to the construction of the 161-MW Wildorado wind project and four other wind projects totaling 181 MW. Also included are expenditures for dust collection and mitigation system and various other smaller projects. These expenditures are planned to be financed by cash on hand, cash generated from operations or existing subsidiary credit agreements.

Other Commitments

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

At December 31, 2006, Midwest Generation was party to a long-term power purchase contract with Calumet Energy Team LLC entered into as part of the settlement agreement with Commonwealth Edison, which terminated Midwest Generation's obligation to build additional gas-fired generation in the Chicago area. The contract requires Midwest Generation to pay a monthly capacity payment and gives Midwest Generation an option to purchase energy from Calumet Energy Team at prices based primarily on operations and maintenance and fuel costs. These minimum commitments are estimated to aggregate $17 million in the next five years: $4 million each year, 2007 to 2010 and less than $1 million in 2011.

Guarantees and Indemnities

Edison International's subsidiaries have various financial and performance guarantees and indemnifications which are issued in the normal course of business. As discussed below, these contracts included performance guarantees, guarantees of debt and indemnifications.

Tax Indemnity Agreements

In connection with the sale-leaseback transactions that EME has entered into related to the Powerton and Joliet Stations in Illinois, the Collins Station in Illinois, and the Homer City facilities in Pennsylvania, EME and several of its subsidiaries entered into tax indemnity agreements. Under these tax indemnity agreements, these entities 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 potential obligations, EME cannot determine a maximum potential liability which would be triggered by a valid claim from the lessors. EME has not recorded a liability related to these indemnities. In connection with the termination of the Collins Station lease in April 2004, Midwest Generation will continue to have obligations under the tax indemnity agreement with the former lease equity investor. For more information about the termination of the Collins Station lease, see "Results of Operations and Historical Cash Flow Analysis—Earnings (Loss) from Continuing Operations—2005 vs. 2004."

Indemnities Provided as Part of EME's Acquisition of the Illinois Plants

In connection with the acquisition of the Illinois plants, EME agreed to indemnify Commonwealth Edison with respect to specified environmental liabilities before and after December 15, 1999, the date of sale. The indemnification claims are reduced by any insurance proceeds and tax benefits related to such claims and are subject to a requirement that Commonwealth Edison takes all reasonable steps to mitigate losses related to any such indemnification claim. Due to the nature of the obligation under this indemnity, a maximum potential liability cannot be determined. This indemnification for environmental liabilities is not limited in term and would be triggered by a valid claim from Commonwealth Edison. Except as discussed below, EME has not recorded a liability related to this indemnity.

Midwest Generation entered into a supplemental agreement with Commonwealth Edison and Exelon Generation on February 20, 2003 to resolve a dispute regarding interpretation of its reimbursement obligation for asbestos claims under the environmental indemnities set forth in the asset sale agreement. Under this supplemental agreement, Midwest Generation agreed to reimburse Commonwealth Edison and Exelon Generation for 50% of specific asbestos claims pending as of February 2003 and related expenses less recovery of insurance costs, and agreed to a sharing arrangement for liabilities and expenses associated with future asbestos-related claims as specified in the agreement. As a general matter, Commonwealth Edison and Midwest Generation apportion responsibility for future asbestos-related claims based upon the number of exposure sites that are Commonwealth Edison locations or Midwest Generation locations. 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 of either party to terminate). Payments are made under this indemnity upon tender by Commonwealth Edison of appropriate proof of liability for an asbestos-related settlement, judgment, verdict, or expense. There were approximately 186 cases for which Midwest Generation was potentially liable and that had not been settled and dismissed at December 31, 2006. Midwest Generation had recorded a $65 million liability at December 31, 2006 related to this matter.

The amounts recorded by Midwest Generation for the asbestos-related liability are based upon a number of assumptions. Future events, such as the number of new claims to be filed each year, the average cost of disposing of claims, as well as the numerous uncertainties surrounding asbestos litigation in the United States, could cause the actual costs to be higher or lower than projected.

Indemnity Provided as Part of EME's Acquisition of the Homer City Facilities

In connection with the acquisition of the Homer City facilities, EME Homer City agreed to indemnify the sellers with respect to specific environmental liabilities before and after the date of sale. Payments would be triggered under this indemnity by a claim from the sellers. EME guaranteed the obligations of EME Homer City. Due to the nature of the obligation under this indemnity provision, it is not subject to a maximum potential liability and does not have an expiration date. EME has not recorded a liability related to this indemnity.

Indemnities Provided Under Asset Sale Agreements

The asset sale agreements for the sale of EME's international assets contain indemnities from EME to the purchasers, including indemnification for taxes imposed with respect to operations of the assets prior to the sale and for pre-closing environmental liabilities. Not all indemnities under the asset sale agreements have specific expiration dates. Payments would be triggered under these indemnities by valid claims from the sellers or purchasers, as the case may be. At December 31, 2006 EME had recorded a liability of $95 million related to these matters.

In connection with the sale of various domestic assets, EME has from time to time provided indemnities to the purchasers for taxes imposed with respect to operations of the asset prior to the sale. EME has 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. Not all indemnities under the asset sale agreements 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.

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 agreements terminate, 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 sales agreements. In addition, a subsidiary of EME has guaranteed the obligations of Sycamore Cogeneration Company under its project power sales agreement to repay capacity payments to the project's power purchaser in the event that the project unilaterally terminates its performance or reduces its electric power producing capability during the term of the power sales agreements. The obligations under the indemnification agreements as of December 31, 2006, if payment were required, would be $101 million. EME has not recorded a liability related to these indemnities.

Indemnity Provided as Part of the Acquisition of Mountainview

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

Other Edison International Indemnities

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

OFF-BALANCE SHEET TRANSACTIONS

This section of the MD&A discusses off-balance sheet transactions at MEHC and Edison Capital. SCE does not have 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 MEHC, MEHC's obligations to one of its subsidiaries, and leveraged leases at Edison Capital.

MEHC's Off-Balance Sheet Transactions

Introduction

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

EME has a number of investments in power projects that are accounted for under the equity method. Under the equity method, the project assets and related liabilities are not consolidated in EME's consolidated balance sheet. Rather, EME'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 QFs, those which produce electrical energy and steam, or other forms of energy, and which meet the requirements set forth in PURPA. Prior to the passage of the Energy Policy Act of 2005, these regulations limited EME's ownership interest in QFs 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.

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, 2006, entities which EME has accounted for under the equity method had indebtedness of $524 million, of which $252 million is proportionate to EME's ownership interest in these projects.

Sale-Leaseback Transactions

EME has entered into sale-leaseback transactions related to the Powerton and Joliet Stations in Illinois and the Homer City facilities in Pennsylvania. See "Commitments, Guarantees and Contingencies—Operating and Capital Lease Obligations." Each of these transactions was completed and accounted for in accordance with SFAS No. 98, which requires, among other things, that all 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 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. The lessor debt takes the form generally referred to as secured lease obligation bonds.

EME's subsidiaries account for these leases as financings in their separate financial statements due to specific guarantees provided by EME or another one of 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 SFAS No. 98 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, resulted in an increase in consolidated net income by $61 million, $72 million and $73 million in 2006, 2005 and 2004, respectively.

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

In millions	Acquisition Price	Equity Investor	Original Equity Investment in Owner/Lessor	Amount of Lessor Debt at December 31, 2006	Maturity Date of Lessor Debt
Power Station(s):					
Powerton/Joliet	$ 1,367	PSEG/	$ 238	$ 330.8 Series A	2009
		Citigroup, Inc.		$ 679.1 Series B	2016
Homer City	1,591	GECC/	798	$ 276.0 Series A	2019
		Metropolitan		$ 521.2 Series B	2026
		Life Insurance			
		Company[1]			

PSEG – PSEG Resources, Inc.

GECC – General Electric Capital Corporation

[1] On September 29, 2005, GECC sold 10% of its investment to Metropolitan Life Insurance Company.

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, 2006 and 2005, prepaid rent on these leases was $556 million and $395 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 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 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.

EME's minimum lease obligations under its power related leases are set forth under "Commitments, Guarantees and Contingencies—Operating and Capital Lease Obligations."

EME's Obligations to Midwest Generation

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 EME's consolidated balance sheet. This obligation was 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 following table summarizes principal payments due under this intercompany loan:

In millions	Year Ended December 31,	Principal Amount	Interest Amount	Total
2007		$ 3	$ 113	$ 116
2008		4	112	116
2009		5	112	117
2010		4	112	116
2011		9	111	120
Thereafter		1,334	401	1,735
Total		$ 1,359	$ 961	$ 2,320

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 Principles Board Opinion No. 18, The *Equity Method of Accounting for Investments in Common Stock*. 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 significant organizational matters. 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%. The debt of those partnerships and limited liability companies is secured by real property and is nonrecourse to Edison Capital, except in limited cases where Edison Capital has guaranteed the debt. At December 31, 2006, Edison Capital had made guarantees to lenders in the amount of $2 million.

Edison Capital has also invested in three limited partnership funds which make investments in infrastructure and infrastructure-related projects. Those funds follow special investment company accounting which requires the fund to account for its investments at fair value. Although Edison Capital would not follow special investment company accounting if it held the funds' investment directly, Edison Capital records its proportionate share of the funds' results as required by the equity method.

At December 31, 2006, entities that Edison Capital has accounted for under the equity method had indebtedness of approximately $1.6 billion, of which approximately $600 million is proportionate to Edison Capital's ownership interest in these projects. Substantially all of this debt is nonrecourse 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 nonrecourse to Edison Capital and is not recorded on Edison International's balance sheet in accordance with SFAS No. 13, Accounting for Leases.

At December 31, 2006, Edison Capital had net investments, before deferred taxes, of $2.5 billion in its leveraged leases, with nonrecourse debt in the amount of $4.8 billion.

OTHER DEVELOPMENTS

Environmental Matters

The operating affiliates of Edison International are subject to numerous federal and state environmental laws and regulations, which require them 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 its operating affiliates are in substantial compliance with existing environmental regulatory requirements.

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

Edison International's projected environmental capital expenditures over the next five years are: 2007 – $444 million; 2008 – $471 million; 2009 – $501 million; 2010 – $686 million; and 2011 – $880 million. The projected environmental capital expenditures are mainly for undergrounding certain transmission and distribution lines at SCE and upgrading environmental controls at EME.

Air Quality Standards

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

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

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

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

Clean Air Act

On May 12, 2005, the CAIR was published in the Federal Register. The CAIR requires 28 eastern states and the District of Columbia to address ozone attainment issues by reducing regional NO_x and SO_2 emissions. The CAIR reduces the current Clean Air Act Title IV Phase II SO_2 emissions allowance cap for 2010 and 2015 by 50% and 65%, respectively. The CAIR also requires reductions in regional NO_x emissions in 2009 and 2015 by 53% and 61%, respectively, from 2003 levels. The CAIR has been challenged in court, which may result in changes to the substance of the rule and to the timetables for implementation.

EME expects that compliance with the CAIR and the regulations and revised SIPs developed as a consequence of the CAIR will result in increased capital expenditures and operating expenses. EME's approach to meeting these obligations will consist of a blending of capital expenditure and emission allowance purchases that will be based on an ongoing assessment of the dynamics of its market conditions.

Illinois

On December 11, 2006, Midwest Generation entered into an agreement with the Illinois EPA to reduce mercury, NO_x and SO_2 emissions at the Illinois plants. The agreement has been embodied in rule language, called the CPS, and Midwest Generation's obligations under the agreement are conditioned upon the formal adoption of the CPS as an Illinois rule. On January 5, 2007, the Illinois EPA and Midwest Generation jointly filed the CPS in the pending state rulemaking related to the Illinois SIP for the CAIR. Midwest Generation expects the CPS to become final in the spring of 2007 and believes that, upon adoption, the CPS will provide greater predictability of the timing and amount of emissions reductions which will be required of the Illinois plants for these pollutants through 2018. No assurance can be given that all required regulatory approvals will be received, and if not received, Midwest Generation will remain subject to existing and future requirements as to emissions of these pollutants.

If the agreement is implemented as contemplated, Midwest Generation will be required to achieve specified emissions reductions through a combination of environmental retrofits or unit shutdowns. The agreement contemplates three phases with each phase relating to one of the pollutants involved. Capital expenditures will be required for each phase.

The first phase involves installing activated carbon injection technology in 2008 and 2009 for the removal of mercury, a technology which EME has been testing at some of its plants. Capital expenditures relating to these controls are currently estimated to be approximately $60 million.

The second phase requires the installation of additional controls by the end of 2011 to further reduce NO_x emissions from units to be determined by Midwest Generation in order to achieve an agreed-on fleetwide level of NO_x emissions per million Btu. Capital expenditures for these controls are currently estimated to be approximately $450 million.

Thereafter, during the third phase of the plan, the focus will be on the reduction of SO_2 emissions. Midwest Generation will be required either to place controls on several units at the Illinois plants between 2012 and 2018 for this purpose or to remove them from service. Midwest Generation will consider many factors in making this choice including, among others, an assessment of the cost and performance of environmental technologies and equipment, the remaining estimated useful life of each affected unit and the market outlook for the prices of various commodities including electrical energy and capacity, coal and natural gas. In view of the many factors involved, Midwest Generation has not yet determined what actions it may take at each affected unit to provide for optimal compliance with the agreement during its third phase. At this time, however, additional capital expenditures during the third phase of the plan are estimated as being in the range of approximately $2.2 billion to $2.9 billion, depending on the number of units on which controls are placed versus the number which are removed from service. For the reasons described above, actual capital expenditures may vary substantially from the above estimates.

On May 30, 2006, the Illinois EPA submitted a proposed regulation to the Illinois Pollution Control Board to implement the Illinois SIP required for compliance with the CAIR. The Illinois Pollution Control Board held hearings on this SIP on October 10, 2006 and November 28, 2006. As noted previously, on January 5, 2007 the Illinois EPA and Midwest Generation filed the CPS in the pending Illinois rulemaking.

Pennsylvania

The Pennsylvania Environmental Quality Board accepted the PADEP's proposed SIP to implement the CAIR on February 20, 2007. The SIP is very similar to the Federal CAIR with modest NO_x set asides for generation from renewables and waste coal. At this time EME plans to comply with the proposal using existing pollution control equipment supplemented with the purchase of SO_2 credits for the first phase of the rule which is effective in 2010.

Mercury Regulation

The CAMR, published in the Federal Register on May 18, 2005, creates a market-based cap-and-trade program to reduce nationwide utility emissions of mercury in two distinct phases. In the first phase of the program, which will come into effect in 2010, the annual nationwide cap will be 38 tons. Emissions of mercury are to be reduced primarily by taking advantage of mercury reductions achieved by reducing SO_2 and NO_x emissions under the CAIR. In the second phase, which is to take effect in 2018, coal-fired power plants will be subject to a lower annual cap, which will reduce emissions nationwide to 15 tons. States may join the trading program by adopting the CAMR model trading rule in state regulations, or they may adopt regulations that mirror the necessary components of the model trading rule. States are not required to adopt a cap-and-trade program and may promulgate alternative regulations, such as command and control regulations, that are equivalent to or more stringent than the CAMR's suggested cap-and-trade program. Any program adopted by a state must be approved by the US EPA.

Contemporaneous with the adoption of the CAMR, the US EPA rescinded its previous finding that mercury emissions from coal-fired power plants had to be regulated as a hazardous air pollutant pursuant to Section 112 of the federal Clean Air Act, which would have imposed technology-based standards. Both the US EPA's rescission action and the CAMR are being challenged in the courts. Because EME cannot predict the outcome of these challenges, which could result in changes to the CAMR rules and timetables, the full impact of this regulation currently cannot be assessed.

Illinois

The final state rule for the reduction of mercury emissions in Illinois was adopted and became effective on December 21, 2006. The rule requires a 90% reduction of mercury emissions from coal-fired power plants averaged across company-owned Illinois stations and a minimum reduction of 75% for individual generating sources by July 1, 2009. The rule requires each station to achieve a 90% reduction by January 1, 2014 and, because emissions are measured on a rolling 12-month average, stations must install equipment necessary to meet the January 1, 2014, 90% reduction by January 1, 2013. Buying or selling of emission allowances under the federal CAMR cap and trade program would be prohibited.

Midwest Generation's pending CPS, if adopted, will supersede this rule for the Illinois plants. The CPS requires installation of activated carbon injection technology for the removal of mercury on all Midwest Generation units by July 2009 (except for three units to be shut down by the end of 2010), prohibits participation in the federal cap-and-trade program, and requires a 90% removal of mercury by unit by the end of 2015. While its CPS is pending, Midwest Generation has filed an appeal of the state's mercury rule that would require a 90% fleetwide reduction in mercury emissions by July 2009.

Pennsylvania

On February 17, 2007, the PADEP published in the Pennsylvania Bulletin regulations that would require coal-fired power plants to reduce mercury emissions by 80% by 2010 and 90% by 2015. The rule does not allow the use of emissions trading to achieve compliance. The rule became final upon publication.

At this time, EME expects the Homer City facilities to achieve compliance by the 2010 deadline with mercury removal achieved by an existing flue gas desulfurization system on one generating unit and by sorbent injection on the other two units. EME has deferred making commitments for the installation of further environmental controls at the Homer City facilities at this time, but continues to study available environmental control technologies and estimated costs to reduce SO_2 and mercury and to monitor developments related to mercury and other environmental regulations.

Water Quality Regulation

Clean Water Act—Cooling Water Intake Structures

On July 9, 2004, the US EPA published the final Phase II rule implementing Section 316(b) of the Clean Water Act establishing standards for cooling water intake structures at existing large power plants. The purpose of the regulation is to reduce substantially the number of aquatic organisms that are pinned against cooling water intake structures or drawn into cooling water systems. Pursuant to the regulation, a demonstration study must be conducted when applying for a new or renewed National Pollutant Discharge Elimination System wastewater discharge permit. If one can demonstrate that the costs of meeting the presumptive standards set forth in the regulation are significantly greater than the costs that the US EPA assumed in its rule making or are significantly disproportionate to the expected environmental benefits, a site-specific analysis may be performed to establish alternative standards. Depending on the findings of the demonstration studies, cooling towers and/or other mechanical means of reducing impingement and entrainment of aquatic organisms may be required. EME has begun to collect impingement and entrainment data at its potentially affected Midwest Generation facilities in Illinois to begin the process of determining what corrective actions may need to be taken.

The Phase II cooling water intake structure rule was challenged in the courts, and the cases were consolidated and transferred to the United States Court of Appeals for the Second Circuit. On January 25, 2007, the Second Circuit granted the petitions challenging the rule and remanded the rule to the US EPA for further proceedings. Although the Phase II rule could have a material impact on EME's operations, EME cannot reasonably determine the financial impact on it at this time because it is still collecting the data required by the regulation and because the challenges mentioned above may affect the obligations imposed by the rule.

Illinois

The Illinois EPA is reviewing the water quality standards for the Des Plaines River adjacent to the Joliet Station and immediately downstream of the Will County Station to determine if the use classification should be upgraded. If the existing use classification is changed, the limits on the temperature of the discharges from the Joliet and Will County plants may be made more stringent. The Illinois EPA has also begun a review of the water quality standards for the Chicago River and Chicago Sanitary and Ship Canal which are adjacent to the Fisk and Crawford Stations. Proposed changes to the existing standards are still being developed. Accordingly, EME is not able to estimate the financial impact of potential changes to the water quality standards. However, the cost of additional cooling water treatment, if required, could be substantial.

Pennsylvania

The discharge from the treatment plant receiving the wastewater stream from EME's Unit 3 flue gas desulfurization system at the Homer City facilities has exceeded the stringent water-quality based limits for selenium in the station's National Pollutant Discharge Elimination System permit. As a result, EME was notified in April 2002 by the PADEP that it was included in the Quarterly Noncompliance Report submitted to the US EPA. With PADEP's approval, EME has undertaken a pilot program utilizing biological treatment. EME prepared a draft of a consent order and agreement addressing the selenium issue and presented it to the PADEP for consideration in connection with the renewal of the station's NPDES permit. The PADEP has included civil penalties in consent agreements related to other facilities with selenium treatment issues, but the amount of civil penalties that may be assessed against EME cannot be estimated at this time.

Climate Change

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

On December 20, 2005, seven northeastern states entered into a Memorandum of Understanding to create a regional initiative to establish a cap and trade GHG program for electric generators, referred to as the RGGI. In August 2006, the participating states issued a model rule to be used as a basis for individual state legislative and regulatory action to implement the program. Illinois and Pennsylvania are not signatories to the RGGI, although Pennsylvania has participated as an observer of the process. Recent reports indicate that Pennsylvania is planning to announce a climate change policy that may include joining the RGGI. If Pennsylvania were to join the RGGI, this could have a material impact on EME's Homer City facilities.

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

Environmental Remediation

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 the 35 identified sites at SCE (23 sites) and EME (12 sites related to Midwest Generation) is $81 million, $78 million of which is related to SCE. 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 the recorded liability by up to $123 million, all 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. In addition to the identified sites (sites in which the upper end of the range of costs is at least $1 million), SCE also has 32 immaterial sites whose total liability ranges from $3 million (the recorded minimum liability) to $8 million.

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

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 the identified sites over a period of up to 30 years. Remediation costs in each of the next several years are expected to range from $11 million to $25 million. Recorded costs for 2006 were $14 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 the 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 and State Income Taxes

Edison International received Revenue Agent Reports from the IRS in August 2002 and in January 2005 asserting deficiencies in federal corporate income taxes with respect to audits of its 1994 – 1996 and 1997 – 1999 tax years, respectively. Edison International expects to conclude the administrative phase of the 1994 – 1996 tax years during the first half of 2007. Many of the asserted tax deficiencies are timing differences and, therefore, amounts ultimately paid (exclusive of penalties), if any, would be deductible on future tax returns of Edison International. Edison International has also submitted affirmative claims to the IRS and state tax agencies which are being addressed in administrative proceedings. Any benefits would be recorded at the earlier of when Edison International believes that the affirmative claim position has a more likely than not probability of being sustained or when a settlement is reached. Certain affirmative claims may be recorded as part of the implementation of FIN 48.

As part of a nationwide challenge of certain types of lease transactions, the IRS has raised issues about the deferral of income taxes associated with Edison Capital's cross-border, leveraged leases.

The IRS is challenging Edison Capital's foreign power plant and electric locomotive sale/leaseback transactions entered into in 1993 and 1994 (Replacement Leases, which the IRS refers to as a sale-in/lease-out or SILO). The IRS is also challenging Edison Capital's foreign power plant and electric transmission system lease/leaseback transactions entered into in 1997 and 1998 (Lease/Leaseback, which the IRS refers to as a lease-in/lease-out or LILO).

Edison Capital also entered into a lease/service contract transaction in 1999 involving a foreign telecommunication system (Service Contract, which the IRS also refers to as a SILO). The IRS has not yet asserted any adjustment for the Service Contract but the IRS has submitted data requests to Edison International regarding the issue as part of the IRS examination of tax years 2000 – 2002.

The following table summarizes estimated federal and state income taxes deferred from these leases. Repayment of these deferred taxes would be accelerated if the IRS prevails:

In millions	Tax Years Under Appeal 1994 - 1999	Tax Years Under Audit 2000 - 2002	Unaudited Tax Years 2003 - 2006	Total
Replacement Leases (SILO)	$ 44	$ 19	$ 23	$ 86
Lease/Leaseback (LILO)	558	562	6	1,126
Service Contract (SILO)	—	126	199	325
	$ 602	$ 707	$ 228	$ 1,537

As of December 31, 2006, the interest on the proposed tax adjustments is estimated to be approximately $417 million. The IRS also seeks a 20% penalty on any sustained tax adjustment.

Edison International believes it properly reported these transactions based on applicable statutes, regulations and case law in effect at the time the transactions were entered into, and it is vigorously defending its tax treatment of these leases. Written protests were filed to appeal the audit adjustments for the tax years under appeal asserting that the IRS's position misstates material facts, misapplies the law and is incorrect. This matter is now being considered by the Administrative Appeals branch of the IRS.

In addition, the payment of taxes, interest and penalties could have a significant impact on earnings and cash flow. In order to commence litigation in certain forums, Edison International must make payments of disputed taxes, along with interest and any penalties asserted by the IRS, and thereafter pursue refunds. On May 26, 2006, Edison International paid $111 million of the taxes, interest and penalties for tax year 1999 followed by a refund claim for the same amount. The cash payment was funded by Edison Capital and accounted for as a deposit which will be refunded with interest to the extent Edison International prevails. Since the IRS did not act on this refund claim within six months from the date the claim was filed, it is deemed denied. Edison International expects to take legal action to assert its refund claim.

A number of other cases involving these kinds of lease transactions are pending before various courts. The first case involving a LILO was recently decided against the taxpayer on summary judgment in the Federal

District Court in North Carolina. That taxpayer has announced its intention to appeal that decision to the Fourth Circuit Court of Appeals.

Edison International expects to file a refund claim for any taxes and penalties paid pursuant to the administrative appeals settlement of the 1994-1996 tax years related to assessed tax deficiencies and penalties on the Replacement Leases. These payments would be treated as a deposit. Edison International may make additional payments related to other tax years to preserve its litigation rights, although, at this time, the amount and timing of these additional payments is uncertain. At this time, Edison International is unable to predict the impact of the ultimate resolution of these matters.

Under FSP FAS 13-2 related to accounting for a change or projected change in the timing of cash flows relating to income taxes generated by a leveraged lease transaction and FIN 48 relating to accounting for uncertainty in income taxes, both issued in July 2006 and effective January 1, 2007, the payments made by Edison International will continue to be treated as a deposit unless it becomes more likely than not that a tax payment related to the resolution of the dispute will be made. If this occurs, the new FSP requires the change in the timing of cash flows to trigger a recalculation of the income allocated over the life of the lease, with the cumulative effect of the change recognized immediately. This could result in a material charge against earnings, although future income would be expected to increase over the remaining terms of the affected leases.

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

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

In December 2006, Edison International reached a settlement with the California Franchise Tax Board regarding the sourcing of gross receipts from the sale of electric services for California state tax apportionment purposes for tax years 1981 to 2004. In the fourth quarter of 2006, Edison International recorded a $49 million benefit related to a tax reserve adjustment as a result of this settlement. In addition to this tax reserve adjustment, Edison International expects to receive a net cash refund of approximately $49 million in the first half of 2007 as a result of this settlement.

Enterprise-Wide Software System Project

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

Midway-Sunset Cogeneration Company

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

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

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

The management of Edison International is responsible for the integrity and objectivity of the accompanying financial statements and related information. The statements have been prepared in accordance with accounting principles generally accepted in the United States of America and are based, in part, on management estimates and judgment. Management believes that the financial statements fairly reflect Edison International's financial position and results of operations.

As a further measure to assure the ongoing objectivity and integrity of financial information, the Audit Committee of the Board of Directors, which is composed of independent directors, meets periodically, both jointly and separately, with management, the independent auditors and internal auditors, who have unrestricted access to the Committee. The Committee annually appoints a firm of independent auditors to conduct an audit of Edison International's financial statements and internal control over financial reporting; reviews accounting, internal control, auditing and 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.

Edison International's independent registered public accounting firm, PricewaterhouseCoopers LLP, are engaged to audit the financial statements included in this Annual Report in accordance with the standards of the Public Company Accounting Oversight Board (United States) and has issued an attestation report on management's assessment of internal controls over financial reporting, as stated in their report which is included in this Annual Report on the following page.

Management's Report on Internal Control over Financial Reporting

Edison International's management is responsible for establishing and maintaining adequate internal control over financial reporting (as that term is defined in Rule 13a-15(f) under the Exchange Act). Under the supervision and with the participation of its Chief Executive Officer and Chief Financial Officer, Edison International's management conducted an evaluation of the effectiveness of internal control over financial reporting based on the framework set forth in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on its evaluation under the COSO framework, Edison International's management concluded that internal control over financial reporting was effective as of December 31, 2006. Management's assessment of the effectiveness of Edison International's internal control over financial reporting as of December 31, 2006 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report on the financial statements in Edison International's 2006 Annual Report to shareholders, which is incorporated herein by this reference.

Disclosure Controls and Procedures

The certifications of the Chief Executive Officer and Chief Financial Officer that are required by Section 302 of the Sarbanes-Oxley Act of 2002 are included as exhibits to Edison International's annual report on Form 10-K. In addition, in 2006, Edison International's Chief Executive Officer provided to the New York Stock Exchange (NYSE) the Annual CEO Certification regarding Edison International's compliance with the NYSE's corporate governance standards.

[THIS PAGE INTENTIONALLY LEFT BLANK]

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Edison International

We have completed integrated audits of Edison International's consolidated financial statements for each of the three years in the period ended December 31, 2006 and of its internal control over financial reporting as of December 31, 2006 in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements

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

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

Internal control over financial reporting

Also, in our opinion, management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that the Company maintained effective internal control over financial reporting as of December 31, 2006 based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control—Integrated Framework* issued by COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP

Los Angeles, California
February 28, 2007

Consolidated Statements of Income

Edison International

In millions, except per-share amounts — Year ended December 31,	**2006**	2005	2004
Electric utility	**$10,312**	$ 9,500	$ 8,448
Nonutility power generation	**2,228**	2,248	1,639
Financial services and other	**82**	104	112
Total operating revenue	**12,622**	11,852	10,199
Fuel	**1,757**	1,810	1,429
Purchased power	**3,409**	2,622	2,332
Provisions for regulatory adjustment clauses – net	**25**	435	(201)
Other operation and maintenance	**3,762**	3,609	3,528
Asset impairment and loss on lease termination	**—**	12	989
Depreciation, decommissioning and amortization	**1,181**	1,061	1,022
Net gain on sale of utility property and plant	**(2)**	(10)	—
Total operating expenses	**10,132**	9,539	9,099
Operating income	**2,490**	2,313	1,100
Interest income	**169**	112	46
Equity in income from partnerships and unconsolidated subsidiaries – net	**79**	136	66
Other nonoperating income	**133**	136	135
Interest expense – net of amounts capitalized	**(807)**	(794)	(985)
Impairment loss on equity method investment	**—**	(55)	—
Other nonoperating deductions	**(63)**	(67)	(80)
Loss on early extinguishment of debt	**(146)**	(25)	—
Income from continuing operations before tax and minority interest	**1,855**	1,756	282
Income tax expense (benefit)	**582**	457	(92)
Dividends on preferred and preference stock of utility not subject to mandatory redemption	**51**	24	6
Minority interest	**139**	167	142
Income from continuing operations	**1,083**	1,108	226
Income from discontinued operations (including gain on disposal of $533 in 2004) – net of tax	**97**	30	690
Income before accounting change	**1,180**	1,138	916
Cumulative effect of accounting change – net of tax	**1**	(1)	—
Net income	**$ 1,181**	$ 1,137	$ 916
Weighted-average shares of common stock outstanding	**326**	326	326
Basic earnings per share:			
Continuing operations	**$ 3.28**	$ 3.38	$ 0.69
Discontinued operations	**0.30**	0.09	2.12
Total	**$ 3.58**	$ 3.47	$ 2.81
Weighted-average shares, including effect of dilutive securities	**330**	332	331
Diluted earnings per share:			
Continuing operations	**$ 3.28**	$ 3.34	$ 0.68
Discontinued operations	**0.29**	0.09	2.09
Total	**$ 3.57**	$ 3.43	$ 2.77
Dividends declared per common share	**$ 1.10**	$ 1.02	$ 0.85

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

Consolidated Statements of Comprehensive Income			**Edison International**
In millions Year ended December 31,	**2006**	2005	2004
Net income	**$ 1,181**	$1,137	$ 916
Other comprehensive income (loss), net of tax:			
Foreign currency translation adjustments:			
Other foreign currency translation adjustments – net	**(1)**	2	(18)
Reclassification adjustment for sale of investment in an international project	**—**	—	(127)
Minimum pension liability adjustment	**(1)**	3	7
Unrealized gain on investments – net	**—**	—	7
Unrealized gains (losses) on cash flow hedges:			
Other unrealized gains (losses) on cash flow hedges – net	**314**	(68)	92
Reclassification adjustment for gain (loss) included in net income	**12**	(159)	88
Other comprehensive income (loss)	**324**	(222)	49
Comprehensive income	**$ 1,505**	$ 915	$ 965

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

Consolidated Balance Sheets

In millions December 31,	Edison International 2006	2005
ASSETS		
Cash and equivalents	**$ 1,795**	$ 1,893
Restricted cash	**59**	60
Margin and collateral deposits	**124**	739
Receivables, less allowances of $29 and $33 for uncollectible accounts at respective dates	**1,014**	1,220
Accrued unbilled revenue	**303**	291
Fuel inventory	**122**	80
Materials and supplies	**270**	261
Accumulated deferred income taxes – net	**203**	218
Derivative assets	**328**	316
Regulatory assets	**554**	536
Short-term investments	**558**	211
Other current assets	**152**	134
Total current assets	**5,482**	5,959
Nonutility property – less accumulated provision for depreciation of $1,627 and $1,424 at respective dates	**4,356**	4,119
Nuclear decommissioning trusts	**3,184**	2,907
Investments in partnerships and unconsolidated subsidiaries	**308**	426
Investments in leveraged leases	**2,495**	2,447
Other investments	**91**	115
Total investments and other assets	**10,434**	10,014
Utility plant, at original cost:		
Transmission and distribution	**17,606**	16,760
Generation	**1,465**	1,370
Accumulated provision for depreciation	**(4,821)**	(4,763)
Construction work in progress	**1,486**	956
Nuclear fuel, at amortized cost	**177**	146
Total utility plant	**15,913**	14,469
Regulatory assets	**2,818**	3,013
Restricted cash	**91**	105
Margin and collateral deposits	**4**	137
Derivative assets	**131**	132
Rent payments in excess of levelized rent expense under plant operating leases	**556**	395
Other long-term assets	**832**	556
Total long-term assets	**4,432**	4,338
Assets of discontinued operations	**—**	11
Total assets	**$36,261**	$34,791

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

Consolidated Balance Sheets		Edison International	
In millions, except share amounts	December 31,	**2006**	2005
LIABILITIES AND SHAREHOLDERS' EQUITY			
Long-term debt due within one year		**$ 488**	$ 745
Accounts payable		**926**	961
Accrued taxes		**155**	262
Accrued interest		**196**	212
Counterparty collateral		**36**	183
Customer deposits		**198**	183
Book overdrafts		**140**	257
Derivative liabilities		**181**	418
Regulatory liabilities		**1,000**	681
Other current liabilities		**983**	1,057
Total current liabilities		**4,303**	4,959
Long-term debt		**9,101**	8,833
Accumulated deferred income taxes – net		**5,297**	5,256
Accumulated deferred investment tax credits		**122**	130
Customer advances		**160**	153
Derivative liabilities		**86**	101
Power-purchase contracts		**32**	64
Accumulated provision for pensions and benefits		**1,099**	745
Asset retirement obligations		**2,759**	2,628
Regulatory liabilities		**3,140**	2,962
Other deferred credits and other long-term liabilities		**1,267**	1,311
Total deferred credits and other liabilities		**13,962**	13,350
Liabilities of discontinued operations		**—**	14
Total liabilities		**27,366**	27,156
Commitments and contingencies (Note 6)			
Minority interest		**271**	301
Preferred and preference stock of utility not subject to mandatory redemption		**915**	719
Common stock, no par value (325,811,206 shares outstanding at each date)		**2,080**	2,043
Accumulated other comprehensive income (loss)		**78**	(226)
Retained earnings		**5,551**	4,798
Total common shareholders' equity		**7,709**	6,615
Total liabilities and shareholders' equity		**$36,261**	$34,791

Authorized common stock is 800 million shares at each reporting period

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

Consolidated Statements of Cash Flows			Edison International
In millions — Year ended December 31,	**2006**	2005	2004
Cash flows from operating activities:			
Net income	**$ 1,181**	$ 1,137	$ 916
Less: income from discontinued operations	**97**	30	690
Income from continuing operations	**1,084**	1,107	226
Adjustments to reconcile to net cash provided by operating activities:			
Cumulative effect of accounting change – net of tax	**(1)**	1	—
Depreciation, decommissioning and amortization	**1,181**	1,061	1,022
Loss on impairment of nuclear decommissioning trusts	**54**	—	—
Other amortization	**99**	107	98
Minority interest	**139**	167	142
Deferred income taxes and investment tax credits	**(136)**	160	557
Equity in income from partnerships and unconsolidated subsidiaries	**(76)**	(136)	(67)
Income from leveraged leases	**(67)**	(71)	(81)
Regulatory assets – long-term	**92**	387	442
Regulatory liabilities – long-term	**18**	(168)	(69)
Loss on early extinguishment of debt	**146**	25	—
Impairment losses	**—**	67	35
Levelized rent expense	**(161)**	(117)	(59)
Other assets	**(239)**	33	(35)
Other liabilities	**393**	143	66
Margin and collateral deposits – net of collateral received	**601**	(586)	(75)
Receivables and accrued unbilled revenue	**208**	(321)	47
Derivative assets – short-term	**182**	(233)	(27)
Derivative liabilities – short-term	**(103)**	137	30
Inventory and other current assets	**(39)**	(71)	42
Regulatory assets – short-term	**(18)**	17	(254)
Regulatory liabilities – short-term	**318**	192	(169)
Accrued interest and taxes	**(123)**	36	(273)
Accounts payable and other current liabilities	**(114)**	196	(82)
Distributions and dividends from unconsolidated entities	**61**	58	84
Operating cash flows from discontinued operations	**94**	22	(481)
Net cash provided by operating activities	**3,593**	2,213	1,119
Cash flows from financing activities:			
Long-term debt issued	**2,350**	1,325	3,570
Long-term debt issuance costs	**(42)**	(25)	(62)
Long-term debt repaid	**(2,249)**	(2,071)	(4,331)
Bonds remarketed – net	**—**	—	350
Issuance of preference stock	**196**	591	—
Redemption of preferred stock	**—**	(148)	(2)
Rate reduction notes repaid	**(246)**	(246)	(246)
Change in book overdrafts	**(118)**	25	43
Short-term debt financing – net	**—**	(88)	(112)
Shares purchased for stock-based compensation	**(169)**	(182)	(109)
Proceeds from stock option exercises	**66**	85	48
Excess tax benefits related to stock option exercises	**27**	—	—
Dividends to minority shareholders	**(162)**	(174)	(146)
Dividends paid	**(352)**	(326)	(261)
Financing cash flows from discontinued operations	**—**	—	(144)
Net cash used by financing activities	**$ (699)**	$(1,234)	$(1,402)

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

Consolidated Statements of Cash Flows			Edison International	
In millions	Year ended December 31,	**2006**	2005	2004
Cash flows from investing activities:				
Capital expenditures		**$(2,536)**	$(1,868)	$(1,733)
Acquisition costs related to nonutility generation plant		**—**	—	(285)
Purchase of interest of acquired companies		**(18)**	(154)	—
Proceeds from sale of property and interest in projects		**89**	10	118
Proceeds from sale of discontinued operations		**—**	124	2,740
Proceeds from nuclear decommissioning trust sales		**3,010**	2,067	2,416
Purchases of nuclear decommissioning trusts investments		**(3,150)**	(2,159)	(2,525)
Proceeds from partnerships and unconsolidated subsidiaries, net of investment		**25**	132	(4)
Purchase of short-term investments		**(511)**	(183)	(301)
Maturities and sales of short-term investments		**137**	140	181
Restricted cash		**12**	49	31
Turbine deposits		**(130)**	(57)	—
Customer advances for construction and other investments		**80**	119	2
Investing cash flows from discontinued operations		**—**	5	58
Net cash provided (used) by investing activities		**(2,992)**	(1,775)	698
Effect of consolidation of variable interest entities on cash		**—**	3	79
Effect of deconsolidation of variable interest entities on cash		**—**	—	(34)
Effect of exchange rate changes on cash		**—**	(1)	50
Net increase (decrease) in cash and equivalents		**(98)**	(794)	510
Cash and equivalents, beginning of year		**1,893**	2,689	2,179
Cash and equivalents, end of year		**1,795**	1,895	2,689
Cash and equivalents – discontinued operations		**—**	(2)	(1)
Cash and equivalents – continuing operations		**$ 1,795**	$ 1,893	$ 2,688

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

Consolidated Statements of Changes in Common Shareholders' Equity				Edison International
In millions	Common Stock	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Common Shareholders' Equity
Balance at December 31, 2003	$1,970	$ (53)	$3,466	$5,383
Net income			916	916
Foreign currency translation adjustments		(14)		(14)
Tax effect		(4)		(4)
Reclassification adjustment for sale of investment in foreign subsidiary		(127)		(127)
Minimum pension liability adjustment		6		6
Tax effect		1		1
Unrealized gain on investment		11		11
Tax effect		(4)		(4)
Other unrealized gain on cash flow hedges		98		98
Tax effect		(6)		(6)
Reclassification adjustment for loss on derivatives included in net income		152		152
Tax effect		(64)		(64)
Common stock dividend declared ($0.85 per share)			(277)	(277)
Shares purchased for stock-based compensation	(34)		(75)	(109)
Proceeds from stock option exercises			48	48
Noncash stock-based compensation	39			39
Balance at December 31, 2004	$1,975	$ (4)	$4,078	$6,049
Net income			1,137	1,137
Foreign currency translation adjustments		4		4
Tax effect		(2)		(2)
Minimum pension liability adjustment		6		6
Tax effect		(3)		(3)
Other unrealized loss on cash flow hedges		(12)		(12)
Tax effect		(56)		(56)
Reclassification adjustment for loss on derivatives included in net income		(266)		(266)
Tax effect		107		107
Common stock dividend declared ($1.02 per share)			(332)	(332)
Shares purchased for stock-based compensation	(20)		(162)	(182)
Proceeds from stock option exercises			85	85
Noncash stock-based compensation	35			35
Excess tax benefits related to stock option exercises	52			52
Capital stock expense and other	1		(8)	(7)
Balance at December 31, 2005	$2,043	$(226)	$4,798	$6,615

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

Consolidated Statements of Changes in Common Shareholders' Equity — Edison International

In millions	Common Stock	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Common Shareholders' Equity
Balance at December 31, 2005	$2,043	$(226)	$4,798	$6,615
Net income			1,181	1,181
Foreign currency translation adjustments		(2)		(2)
Tax effect		1		1
Minimum pension liability adjustment		(1)		(1)
SFAS No. 158 – postretirement benefits		(30)		(30)
Tax effect		10		10
Other unrealized gain on cash flow hedges		528		528
Tax effect		(214)		(214)
Reclassification adjustment for loss on derivatives included in net income		21		21
Tax effect		(9)		(9)
Common stock dividend declared ($1.10 per share)			(358)	(358)
Shares purchased for stock-based compensation	(33)		(136)	(169)
Proceeds from stock option exercises			66	66
Noncash stock-based compensation	42			42
Excess tax benefits related to stock option exercises	28			28
Balance at December 31, 2006	$2,080	$ 78	$5,551	$7,709

Authorized common stock is 800 million shares. Outstanding common stock is 325,811,206 shares for all years presented.

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

Note 1. Summary of Significant Accounting Policies

Edison International's principal wholly owned subsidiaries include: SCE, a rate-regulated electric utility that supplies electric energy to a 50,000 square-mile area of central, coastal and southern California; MEHC, a holding company for EME, which is engaged in the business of developing, acquiring, owning or leasing, operating and selling energy and capacity from independent power production facilities; and Edison Capital, a provider of capital and financial services. Through EME, MEHC also conducts hedging and energy trading activities in power markets open to competition. EME has domestic projects and one foreign project in Turkey; Edison Capital has domestic projects and foreign projects, primarily in Europe, Australia and Africa.

Basis of Presentation

The consolidated financial statements include Edison International and its wholly owned subsidiaries. Edison International's subsidiaries consolidate their subsidiaries in which they have a controlling interest and VIEs in which they are the primary beneficiary. In addition, Edison International's subsidiaries generally use the equity method to account for significant interests in (1) partnerships and subsidiaries in which they own a significant or less than controlling interest and (2) VIEs in which they are not the primary beneficiary. Intercompany transactions have been eliminated, except EME's profits from energy sales to SCE, which are allowed in utility rates.

On April 1, 2006, EME received, as a capital contribution from its affiliate, Edison Capital, ownership interests in a portfolio of wind projects located in Iowa and Minnesota and a small biomass project. EME accounted for this acquisition at Edison Capital's historical cost as a transaction between entities under common control. As a result of this capital contribution, Edison International's nonutility power generation segment now includes the wind assets and biomass power project previously owned by Edison Capital.

SCE's accounting policies conform to accounting principles generally accepted in the United States of America, including the accounting principles for rate-regulated enterprises, which reflect the rate-making policies of the CPUC and the FERC.

Certain prior-year amounts were reclassified to conform to the December 31, 2006 financial statement presentation. Except as indicated, amounts presented in the Notes to the Consolidated Financial Statements relate to continuing operations.

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

Book Overdrafts

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

Cash and Equivalents

Cash and equivalents consist of cash and cash equivalents. Cash equivalents consist of time deposits including certificates of deposit ($439 million at December 31, 2006 and $489 million at December 31, 2005) and other investments ($1.1 billion at December 31, 2006 and $1.2 billion at December 31, 2005) with original maturities of three months or less. Additionally, cash and equivalents of $78 million at December 31, 2006 and $120 million at December 31, 2005 are included for four projects that Edison International is consolidating under an accounting interpretation for VIEs. For a discussion of restricted cash, see "Restricted Cash."

Deferred Financing Costs

Debt premium, discount and issuance expenses are deferred and amortized (on a straight-line basis for SCE and on a basis which approximates the effective interest rate method for MEHC) through interest expense 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. SCE had unamortized loss on reacquired debt of $318 million at December 31, 2006 and $323 million at December 31, 2005 reflected in "regulatory assets" in the long-term section of the consolidated balance sheets. Edison International had unamortized debt issuance costs of $96 million at December 31, 2006 and $42 million at December 31, 2005 reflected in "other long-term assets" on the consolidated balance sheets.

Derivative Instruments and Hedging Activities

Edison International uses derivative financial instruments to manage financial exposure on its investments and fluctuations in commodity prices, interest rates, foreign currency exchange rates, and emission and transmission rights. Edison International manages these risks in part by entering into interest rate swap, cap and lock agreements, and forward commodity transactions, including options, swaps and futures. Edison International has a power marketing and trading subsidiary that markets the energy and capacity of EME's merchant generating fleet and, in addition, trades electric power and energy and related commodity and financial products.

Edison International is exposed to credit loss in the event of nonperformance by counterparties. To mitigate credit risk from counterparties, master netting agreements are used whenever possible and counterparties may be required to pledge collateral depending on the creditworthiness of each counterparty and the risk associated with the transaction.

Edison International records its derivative instruments on its consolidated balance sheets at fair value unless they meet the definition of a normal purchase or sale. The normal purchases and sales exception requires, among other things, physical delivery in quantities expected to be used or sold over a reasonable period in the normal course of business. 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 a designated hedge. For a designated 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 (loss)," and subsequently reclassified into earnings when the forecasted transaction affects earnings. The ineffective portion of the hedge is reflected in earnings immediately. Hedge accounting requires Edison International to formally document, designate, and assess the effectiveness of hedge transactions.

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

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

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

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

EME's risk management and trading operations are conducted by a subsidiary. As a result of a number of industry and credit-related factors, the subsidiary has minimized its price risk management and trading activities not related to EME's power plants or investments in energy projects. To the extent it engages in trading activities, EME's trading subsidiary 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. Financial instruments that are utilized for trading purposes are measured at fair value and are included in the consolidated balance sheets as derivative assets or liabilities. In the absence of quoted market prices, financial instruments are valued at fair value, considering time value, volatility of the underlying commodity, and other factors as determined by EME. Fair value changes for EME's trading operations are reflected in earnings. Derivative assets include the fair value of open financial positions related to trading activities and the present value of net amounts receivable from structured transactions. Derivative liabilities include the fair value of open financial positions related to trading activities.

EME has nontrading derivative financial instruments arising from energy contracts related to the Illinois plants and Homer City. In assessing the fair value of its nontrading 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 the commodity price contracts takes in account quoted market prices, time value of money, volatility of the underlying commodities and other factors. EME's unrealized gains and losses from its energy contracts are classified as part of nonutility power generation revenue.

See further information about Edison International derivative instruments in Note 2.

Dividend Restriction

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

Earnings Per Share

Edison International computes EPS using the two-class method, which is an earnings allocation formula that determines EPS for each class of common stock and participating security. Edison International's participating securities are vested stock options that earn dividend equivalents on an equal basis with common shares. The number of participating shares increased in 2006, as stock options awarded since 2003 received dividend equivalents. Stock options from 2000 through 2002 were granted without a dividend equivalent feature. As the awards since 2003 vest, the number of participating shares increases. Further, the 1998 and 1999 options did not earn dividend equivalents until 2006, when performance criteria were triggered.

Basic EPS is computed by dividing net income available for common stock by the weighted-average number of common shares outstanding. Net income available for common stock was $1.167 billion, $1.130 billion and

$916 million in 2006, 2005 and 2004, respectively. In determining net income available for common stock, dividends on preferred and preferred stock have been deducted.

For the diluted EPS calculation, dilutive securities (stock-based compensation awards) are added to the weighted-average shares. Stock options with exercise prices greater than or equal to the market price are not included in the dilutive securities calculation. Dilutive securities are excluded from the diluted EPS calculation for items with a net loss due to their antidilutive effect.

Impairment of Investments and Long-Lived Assets

Edison International evaluates the impairment of its investments in projects and other long-lived assets based on a review of estimated cash flows expected to be generated whenever events or changes in circumstances indicate the carrying amount of such investments or assets may not be recoverable. If the carrying amount of the investment or asset exceeds the amount of the expected future cash flows, undiscounted and without interest charges, then an impairment loss for investments in projects and other long-lived assets is recognized in accordance with Accounting Principles Board Opinion No. 18, The Equity Method of Accounting for Investments in Common Stock, and SFAS No. 144, respectively. In accordance with SFAS No. 71, SCE's impaired assets are recorded as a regulatory asset if it is deemed probable that such amounts will be recovered from the ratepayers.

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 depreciable property and leveraged leases, for tax and accounting purposes. These differences result in deferred tax assets and liabilities, which are included within Edison International's consolidated balance sheet.

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

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

Inventory

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

Leases

Rent expense under operating leases for property, plant and equipment is levelized over the terms of the leases.

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

The gain on the sale of the power facilities involved in EME's sale-leaseback transactions in 2000 and 2001 has been deferred and is being amortized over the terms of the respective leases.

See "Lease Commitments" in Note 6 for additional information on operating leases, capital leases and the sale-leaseback transactions.

Margin and Collateral Deposits

Margin and collateral deposits include margin requirements and cash deposited with counterparties and brokers as credit support under energy contracts. The amount of margin and collateral deposits generally varies based on changes in the value of the contracts. Some of these deposits with counterparties and brokers earn interest at various rates.

New Accounting Pronouncements

Accounting Pronouncements Adopted

SFAS No. 123(R) requires companies to use the fair value accounting method for stock-based compensation. Edison International implemented SFAS No. 123(R) in the first quarter of 2006 and applied the modified prospective transition method. Under the modified prospective method, SFAS No. 123(R) was applied effective January 1, 2006 to the unvested portion of awards previously granted and will be applied to all prospective awards. Prior financial statements were not restated under this method. SFAS No. 123(R) resulted in the recognition of expense for all stock-based compensation awards. In addition, Edison International elected to calculate the pool of windfall tax benefits as of the adoption of SFAS No. 123(R) based on the method (also known as the short-cut method) proposed in FSP FAS 123(R)-3, Transition Election to Accounting for the Tax Effects of Share-Based Payment Awards. Prior to January 1, 2006, Edison International used the intrinsic value method of accounting, which resulted in no recognition of expense for its stock options. Prior to adoption of SFAS No. 123(R), Edison International presented all tax benefits of deductions resulting from the exercise of stock options as a component of operating cash flows under the caption "Other liabilities" in the consolidated statements of cash flows. SFAS No. 123(R) requires the cash flows resulting from the tax benefits that occur from estimated tax deductions in excess of the compensation cost recognized for those options (excess tax benefits) to be classified as financing cash flows. The $27 million excess tax benefit is classified as a financing cash inflow in 2006. Due to the adoption of SFAS No. 123(R), Edison International recorded a cumulative effect adjustment that increased net income by approximately $1 million, net of tax, in the first quarter of 2006, mainly to reflect the change in the valuation method for performance shares classified as liability awards and the use of forfeiture estimates.

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

In September 2006, the FASB issued SFAS No. 158, which amends the accounting by employers for defined benefit pension plans and PBOPs. SFAS No. 158 requires companies to recognize the overfunded or underfunded status of defined benefit pension and other postretirement plans as assets and liabilities in the balance sheet; the assets and/or liabilities are offset through other comprehensive income (loss). Edison International adopted SFAS No. 158 as of December 31, 2006. Edison International recorded regulatory assets and liabilities instead of charges and credits to other comprehensive income (loss) for its postretirement benefit plans that are recoverable in utility rates, in accordance with SFAS No. 71. SFAS No. 158 also requires companies to align the measurement dates for their plans to their fiscal year-ends; Edison International already has a fiscal year-end measurement date for all of its postretirement plans. Upon adoption, Edison International recorded additional postretirement benefit assets of $145 million, additional postretirement liabilities of $333 million (including $30 million classified as current), additional regulatory assets of $303 million, regulatory liabilities of $145 million, and a reduction to accumulated other comprehensive income (loss) (a component of shareholders' equity) of $18 million, net of tax.

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

Accounting Pronouncements Not Yet Adopted

In July 2006, the FASB issued an interpretation (FIN 48) clarifying the accounting for uncertainty in income taxes. An enterprise would be required to recognize, in its financial statements, the best estimate of the impact of a tax position by determining if the weight of the available evidence indicates it is more likely than not, based solely on the technical merits, that the position will be sustained on audit. Edison International will adopt FIN 48 in the first quarter of 2007. Edison International is currently assessing the impact of FIN 48 on its financial statements. Based on the current status of discussions with tax authorities related to open tax years under audit and other information currently available, implementation of FIN 48 is expected to result in a cumulative-effect adjustment increasing retained earnings in a range of approximately $250 million to $300 million upon adoption. The estimated range is subject to final completion of Edison International's analysis and assessment of each uncertain tax position. Edison International will continue to monitor and assess new income tax developments including the IRS' challenge of the sale/leaseback and lease/leaseback transactions discussed in "Federal and State Income Taxes" in Note 6.

In July 2006, the FASB issued an FSP on accounting for a change or projected change in the timing of cash flows relating to income taxes generated by a leveraged lease transaction (FSP FAS 13-2). The effective date is January 1, 2007. As discussed under "Federal and State Income Taxes" in Note 6, the deferral of income taxes associated with Edison Capital's cross-border, leveraged leases has been challenged by the IRS. If it becomes more likely than not that Edison International would accelerate the payment of deferred taxes for these leases, FSP FAS 13-2 requires the change in the timing of cash flows to trigger a recalculation of the income allocated over the life of the lease, with the cumulative effect of the change recognized immediately. This could result in a material charge against earnings, although future income would be expected to increase over the remaining terms of the affected leases.

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

Nuclear Decommissioning

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

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

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

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

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

Planned Major Maintenance

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

Project Development Costs

Edison International capitalizes direct costs incurred in developing new projects upon attainment of principal activities needed to commence procurement and construction. These costs consist of professional fees, salaries, permits, and other directly related development costs incurred by Edison International. The capitalized costs are amortized over the life of operational projects or charged to expense if Edison International determines the costs to be unrecoverable.

Property and Plant

Utility Plant

Utility plant additions, including replacements and betterments, are capitalized. Such costs include direct material and labor, construction overhead, a portion of administrative and general costs capitalized at a rate authorized by the CPUC, and AFUDC.

AFUDC represents the estimated cost of debt and equity funds that finance utility-plant construction. Currently, AFUDC debt and equity is capitalized during plant construction and reported in interest expense and other nonoperating income, respectively. AFUDC is recovered in rates through depreciation expense over the useful life of the related asset. AFUDC – equity was $32 million in 2006, $25 million in 2005 and $23 million in 2004. AFUDC – debt was $18 million in 2006, $14 million in 2005 and $12 million in 2004.

Depreciation of utility plant is computed on a straight-line, remaining-life basis. Depreciation expense stated as a percent of average original cost of depreciable utility plant was, on a composite basis, 4.2% for 2006, 3.9% for 2005 and 3.9% for 2004.

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

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

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

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

Nonutility Property

Nonutility property, including leasehold improvements and construction in progress, is capitalized at cost. Interest incurred on borrowed funds that finance construction and project development costs are also capitalized.

Capitalized interest was $8 million in 2006, $16 million in 2005 and $9 million in 2004. SCE's Mountainview power plant is included in nonutility property in accordance with the rate-making treatment. EME's capitalized interest is amortized over the depreciation period of the major plant and facilities for the respective project. SCE's capitalized interest is generally amortized over 30 years (the life of the purchased-power agreement under which Mountainview operates).

Depreciation and amortization is primarily computed on a straight-line basis over the estimated useful lives of nonutility properties 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, 3.9% for 2006, 4.0% for 2005 and 4.1% for 2004.

Emission allowances were acquired by EME as part of its Illinois plants and Homer City facilities acquisitions. Although these emission allowances are freely transferable, EME intends to use substantially all of 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 20 years
Building, plant and equipment	3 years to 40 years
Emission allowances	25 years to 34 years
Land easements	60 years
Leasehold improvements	Shorter of life of lease or estimated useful life

Purchased Power

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

Receivables

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

Regulatory Assets and Liabilities

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

Related Party Transactions

Specified administrative services such as payroll and employee benefit programs, all performed by Edison International or SCE employees, are shared among all subsidiaries of Edison International, and the cost of these corporate support services are allocated to all subsidiaries. Costs are allocated based on one of the following formulas: percentage of time worked, equity in investment and advances, number of employees, or multi-factor (operating revenue, operating expenses, total assets and number of employees). In addition, services of Edison International (or SCE) employees are sometimes directly requested by an Edison International subsidiary and these services are performed for the subsidiary's benefit. Labor and expenses of these directly requested services are specifically identified and billed at cost.

Four EME subsidiaries have 49% to 50% ownership in partnerships that sell electricity generated by their project facilities to SCE under long-term power purchase agreements with terms and pricing approved by the CPUC. Beginning March 31, 2004, Edison International consolidates these projects. See Note 14 for further information regarding VIEs.

An indirect wholly owned affiliate of EME has entered into operation and maintenance agreements with partnerships in which EME has a 50% or less ownership interest. EME recorded revenue under these agreements of $26 million in 2006, and $24 million for each of 2005 and 2004. EME's accounts receivable with this affiliate totaled $7 million at both December 31, 2006 and 2005.

Restricted Cash

Edison International had total restricted cash of $150 million at December 31, 2006 and $165 million at December 31, 2005. The restricted amounts included in current assets are primarily used to make scheduled payments on the current maturities of rate reduction notes issued on behalf of SCE by a special purpose entity, as well as to serve as collateral at Edison Capital for outstanding letters of credit. The restricted amounts included in other long-term assets are primarily to pay amounts required for debt payments and letter of credit expenses at EME.

Revenue Recognition

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

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

Generally, nonutility power generation revenue is recorded as electricity is generated or services are provided unless it is subject to SFAS No. 133 and does not qualify for the normal purchases and sales exception. EME's subsidiaries enter into power and fuel hedging, optimization transactions and energy trading contracts, all subject to market conditions. One of EME's subsidiaries executes these transactions primarily through the use of physical forward commodity purchases and sales and financial commodity swaps and options. With respect to its physical forward contracts, EME's subsidiaries generally act as the principal, take title to the commodities, and assume the risks and rewards of ownership. Therefore, EME's subsidiaries record settlement of nontrading physical forward contracts on a gross basis. Consistent with EITF No. 03-11, Reporting Realized Gains and Losses on Derivative Instruments that are Subject to FASB Statement No. 133, Accounting for Derivative Instruments and Hedging Activities, and Not Held for Trading Purposes, EME nets the cost of purchased power against related third party sales in markets that use locational marginal pricing, currently PJM. Financial swap and option transactions are settled net and, accordingly, EME's subsidiaries do not take title to the underlying commodity. Therefore, gains and losses from settlement of financial swaps and options are recorded net. Managed risks typically include commodity price risk associated with fuel purchases and power sales. In addition, nonutility power generation revenue includes revenue under certain long-term power sales contracts subject to EITF No. 91-6, Revenue Recognition of Long-term Power Sales Contracts, which is recognized based on the output delivered at the lower of the amount billable or the average rate over the contract term. The excess of the amounts billed over the portion recorded as nonutility power generation revenue is reflected in the caption "Other deferred credits and other long-term liabilities" on the consolidated balance sheets.

Financial services and other revenue is generally derived from: leveraged leases, which is recorded by recognizing income 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.

Short-term Investments

Edison International's short-term investments are primarily composed of short-term investments at EME. At December 31, 2006 and 2005, EME had classified these marketable securities as held-to-maturity in accordance with SFAS No. 115, Accounting for Certain Investments in Debt and Equity Securities. The securities were carried at amortized costs plus accrued interest which approximated their fair value. Gross unrealized holding gains and losses on these short-term investments were not material.

EME's short-term investments, which all mature within one year, consisted of the following:

In millions	December 31,	2006	2005
Commercial paper		**$417**	$ 99
Certificates of deposit		**141**	34
Time deposits		**—**	50
Total		**$558**	$183

At December 31, 2005, SCE also had short-term investments of $28 million in variable-rate demand notes, classified as available-for-sale.

In addition, EME had marketable securities classified as available-for-sale under SFAS No. 115 during 2005 and 2004. Sales of EME's auction rate securities were $140 million and $181 million in 2005 and 2004, respectively. Purchases of EME's auction rate securities were $301 million in 2004. Unrealized gains and losses from investments in these securities were not material.

Stock-Based Compensation

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

Prior to January 1, 2006, Edison International accounted for these plans using the intrinsic value method. Upon grant, no stock-based compensation cost for stock options was reflected in net income, as the grant date was the measurement date, and all options granted under these plans had an exercise price equal to the market value of the underlying common stock on the date of grant. Previously, stock-based compensation cost for performance shares was remeasured at each reporting period and related compensation expense was adjusted. As discussed in "New Accounting Pronouncements" above, effective January 1, 2006, Edison International implemented a new accounting standard that requires companies to use the fair value accounting method for stock-based compensation resulting in the recognition of expense for all stock-based compensation awards. Edison International recognizes stock-based compensation expense on a straight-line basis over the requisite service period. Because SCE capitalizes a portion of cash-based compensation and SFAS No. 123(R) requires stock-based compensation to be recorded similarly to cash-based compensation, SCE capitalizes a portion of its stock-based compensation related to both unvested awards and new awards. Edison International recognizes stock-based compensation expense for awards granted to retirement-eligible participants as follows: for stock-based awards granted prior to January 1, 2006, Edison International recognized stock-based compensation expense over the explicit requisite service period and accelerated any remaining unrecognized compensation expense when a participant actually retired; for awards granted or modified after January 1, 2006 to participants who are retirement-eligible or will become retirement-eligible prior to the end of the normal requisite service period for the award, stock-based compensation will be recognized on a prorated basis over the initial year or over the period between the date of grant and the date the participant first becomes eligible for retirement. If Edison International recognized stock-based compensation expense for awards granted prior to January 1, 2006, over a period to the date the participant first became eligible for retirement, stock-based compensation expense would have decreased $8 million for 2006, would have increased $6 million for 2005 and would have increased $13 million for 2004.

Total stock-based compensation expense (reflected in the caption "Other operation and maintenance" on the consolidated statements of income) was $58 million, $81 million and $86 million for 2006, 2005 and 2004, respectively. The income tax benefit recognized in the income statement was $23 million, $32 million and $34 million for 2006, 2005 and 2004, respectively. Total stock-based compensation cost capitalized was $6 million for 2006.

The following table illustrates the effect on net income and EPS if Edison International had used the fair-value accounting method for 2005 and 2004.

In millions — Year ended December 31,	2005	2004
Net income, as reported	$1,137	$ 916
Add: stock-based compensation expense using the intrinsic value accounting method – net of tax	48	51
Less: stock-based compensation expense using the fair-value accounting method – net of tax	42	57
Pro forma net income	$1,143	$ 910
Basic EPS:		
As reported	$ 3.47	$2.81
Pro forma	3.49	2.79
Diluted EPS:		
As reported	$ 3.43	$2.77
Pro forma	3.45	2.75

Note 2. Derivative Instruments and Hedging Activities

EME recorded net gains of approximately $137 million, $202 million and $29 million in 2006, 2005 and 2004, respectively, arising from energy trading activities, which are reflected in nonutility power generation revenue on the consolidated statements of income. EME netted 4.3 million MWh and 3.9 million MWh of sales and purchases of physically settled, gross purchases and sales during 2006 and 2005, respectively.

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

EME recorded net unrealized gains (losses) arising from nontrading derivative activities of $65 million, $(60) million and $(17) million in 2006, 2005 and 2004, respectively, which are reflected in nonutility power generation revenue on the consolidated statements of income.

Note 3. Liabilities and Lines of Credit

Long-Term Debt

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

MEHC used the common stock of EME as collateral for MEHC's senior secured notes. MEHC's senior secured notes are nonrecourse to Edison International and EME, and accordingly, Edison International and EME have no obligations under these senior secured notes. These senior secured notes contain restrictions on MEHC's ability to pay dividends unless it has an interest coverage ratio of at least 2.0 to 1.0 as defined in the indenture. At December 31, 2006, MEHC's interest coverage ratio was 2.79 to 1.0.

In connection with Midwest Generation's financing activities, EME has given first and second priority collateral interests in substantially all the coal-fired generating plants owned by Midwest Generation and the assets relating to those plants and receivables of EMMT directly related to Midwest Generation's hedging activities. The amount of assets pledged or mortgaged totaled approximately $2.9 billion at December 31, 2006. In addition to these assets, Midwest Generation's membership interests and the capital stock of Edison Mission Midwest Holdings were pledged. Emission allowances have not been pledged.

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

Long-term debt is:

In millions December 31,	2006	2005
First and refunding mortgage bonds:		
2007 – 2037 (4.65% to 6.0% and variable)	**$3,525**	$2,775
Rate reduction notes:		
2007 (6.42%)	**246**	493
Pollution-control bonds:		
2015 – 2035 (2.9% to 5.55% and variable)	**1,196**	1,196
Debentures and notes:		
2007 – 2053 (noninterest-bearing to 13.5%)	**4,641**	5,133
Long-term debt due within one year	**(488)**	(745)
Unamortized debt discount – net	**(19)**	(19)
Total	**$9,101**	$8,833

Note: Rates and terms as of December 31, 2006.

EME used the net proceeds of its June 2006 offering of senior notes ($500 million aggregate principal amount of 7.5% senior notes due June 15, 2013 and $500 million aggregate principal amount of 7.75% senior notes due June 15, 2016), together with cash on hand, to purchase its 10% senior notes due August 15, 2008 and its 9.875% senior notes due April 15, 2011. The net proceeds of the offering of the senior notes, together with cash on hand, were also used to pay related tender premiums, consent fees and accrued interest. EME recorded a $146 million loss on early extinguishment of debt during 2006.

Long-term debt maturities and sinking-fund requirements for the next five years are: 2007 – $488 million; 2008 – $848 million; 2009 – $765 million; 2010 – $316 million; and 2011 – $329 million.

Short-Term Debt

Short-term debt is used to finance fuel inventories, balancing account undercollections and general cash requirements, including power purchase payments. Edison International had no outstanding short-term debt at either December 31, 2006 or 2005.

Lines of Credit

At December 31, 2006, Edison International and its subsidiaries had $3.5 billion of borrowing capacity available under lines of credit totaling $3.7 billion. SCE had a $1.7 billion line of credit with $1.5 billion available. EME, including its subsidiary, Midwest Generation, had lines of credit of $968 million available under lines of credit totaling $1.0 billion. Edison International (parent) had a $1.0 billion line of credit available. These credit lines have various expiration dates, and when available, can be drawn down at negotiated or bank index rates.

On February 23, 2007, SCE amended its credit facility, increasing the amount of borrowing capacity to $2.5 billion, extending the maturity to February 2012 and removing the first mortgage bond collateral pledge. Also, on the same date, Edison International amended its credit facility, increasing the amount of borrowing capacity to $1.5 billion and extending the maturity to February 2012.

At December 31, 2005, Edison International and its subsidiaries had $2.7 billion of borrowing capacity available under lines of credit totaling $2.9 billion. SCE had a $1.7 billion line of credit with $1.5 billion available. EME had lines of credit of $198 million with $172 million available. Edison International (parent) had a $1.0 billion line of credit available. These credits lines have various expiration dates, and when available, can be drawn down at negotiated or bank index rates.

Preferred Stock Subject to Mandatory Redemption

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

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

The 7.23% Series preferred stock also has mandatory sinking funds, requiring SCE to redeem at least 50,000 shares per year from 2002 through 2006, and 750,000 shares in 2007. However, SCE was allowed to credit previously repurchased shares against the mandatory sinking-fund provisions. In 2005, SCE redeemed the remaining 807,000 shares of 7.23% Series cumulative preferred stock. Since SCE had previously repurchased 193,000 shares of this series, no shares were redeemed in 2004 or 2003. At December 31, 2004, SCE had 43,000 previously repurchased, but not retired, shares available to credit against the mandatory sinking-fund provisions.

Note 4. Income Taxes

The sources of income (loss) before income taxes are:

In millions	Year ended December 31,	**2006**	2005	2004
Domestic		**$1,636**	$1,557	$128
Foreign		**29**	8	6
Total continuing operations		**1,665**	1,565	134
Discontinued operations		**119**	(11)	737
Accounting change		**1**	(2)	—
Total		**$1,785**	$1,552	$871

The components of income tax expense (benefit) by location of taxing jurisdiction are:

In millions	Year ended December 31,	**2006**	2005	2004
Current:				
Federal		**$ 652**	$400	$(560)
State		**149**	103	(36)
Foreign		**1**	(1)	—
		802	502	(596)
Deferred:				
Federal		**(159)**	16	458
State		**(61)**	(61)	46
		(220)	(45)	504
Total continuing operations		**582**	457	(92)
Discontinued operations		**22**	(40)	47
Accounting change		**—**	(1)	—
Total		**$ 604**	$416	$ (45)

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

In millions December 31,	2006	2005
Deferred tax assets:		
Property-related	**$ 474**	$ 424
Unrealized gains and losses	**373**	321
Regulatory balancing accounts	**496**	301
Decommissioning	**167**	163
Accrued charges	**149**	254
Loss and credit carryforwards	**22**	79
Pension and PBOPs	**215**	182
Derivative-related	**—**	162
Other	**400**	447
Total	**$2,296**	$2,333
Deferred tax liabilities:		
Property-related	**$3,560**	$3,480
Leveraged leases	**2,268**	2,215
Capitalized software costs	**148**	173
Regulatory balancing accounts	**393**	607
Unrealized gains and losses	**367**	321
Derivative-related	**84**	—
Other	**570**	575
Total	**$7,390**	$7,371
Accumulated deferred income taxes – net	**$5,094**	$5,038
Classification of accumulated deferred income taxes – net:		
Included in total deferred credits and other liabilities	**$5,297**	$5,256
Included in current assets	**$ 203**	$ 218

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

Year ended December 31,	2006	2005	2004
Federal statutory rate	**35.0%**	35.0%	35.0%
Tax reserve adjustments	**2.5**	(2.1)	(73.9)
Resolution of state audit issue	**(3.0)**	—	—
Resolution of 1991 – 1993 audit cycle	**—**	(3.9)	—
Housing and production credits	**(2.1)**	(2.0)	(22.9)
Property-related	**0.2**	0.2	10.4
Amortization of ITC credits	**(0.5)**	(0.5)	(6.7)
State tax – net of federal deduction	**3.7**	3.3	3.0
ESOP dividend payment	**(0.6)**	(0.7)	(6.2)
Other	**(0.2)**	(0.1)	(7.4)
Effective tax rate	**35.0%**	29.2%	(68.7)%

Edison International's composite federal and state statutory tax rate was approximately 40% (net of the federal benefit for state income taxes) for all years presented. The effective tax rate of 35.0% realized in 2006 was primarily due to the effect on SCE of a settlement with the California Franchise Tax Board regarding a state apportionment issue (see "Federal and State Income Taxes" in Note 6) and the benefits received from low income housing and production tax credits at Edison Capital, partially offset by additional tax reserve accruals at SCE. The effective tax rate of 29.2% realized in 2005 was primarily due to the favorable resolution of the 1991—1993 IRS audit, as well as adjustments made to the tax reserve to reflect the issuance of new IRS regulations and the favorable settlement of other federal and state tax audit issues at SCE and EME, and the benefits received from the low income housing and production tax credits at Edison Capital. The effective tax benefit rate of 68.7% realized in 2004 was primarily due to adjustments to tax liabilities relating to prior years at SCE and the benefits received from low income housing and production tax credits at Edison Capital, partially offset by property-related flow-through items and property-related adjustments at SCE.

At December 31, 2006, Edison International and its subsidiaries had California net operating loss carryforwards of $69 million with expiration dates beginning in 2011 and had state loss carryforwards for other states of $4 million with expiration dates beginning in 2022. At December 31, 2005, Edison International and its subsidiaries had federal tax credits of $31 million with $26 million to expire in 2024. At December 31, 2005, Edison International also had California net operating loss carryforwards of $128 million with expiration dates beginning in 2011 and had state loss carryforwards for other states of $6 million with expiration dates beginning in 2022.

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 and State Income Taxes" in Note 6.

Note 5. 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 $69 million in 2006, $64 million in 2005 and $50 million in 2004.

Pension Plans and Postretirement Benefits Other Than Pensions

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

Pension Plans

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

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

The expected contributions (all by the employer) are approximately $66 million for the year ended December 31, 2007. This amount is subject to change based on, among other things, the limits established for federal tax deductibility.

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

Information on plan assets and benefit obligations is shown below:

In millions Year ended December 31,	2006	2005
Change in projected benefit obligation		
Projected benefit obligation at beginning of year	$3,418	$3,231
Service cost	118	117
Interest cost	181	175
Amendments	12	2
Actuarial loss (gain)	(48)	83
Special termination benefits	8	—
Benefits paid	(279)	(190)
Projected benefit obligation at end of year	$3,410	$3,418
Accumulated benefit obligation at end of year	$2,987	$2,953
Change in plan assets		
Fair value of plan assets at beginning of year	$3,199	$3,062
Actual return on plan assets	488	307
Employer contributions	50	20
Benefits paid	(279)	(190)
Fair value of plan assets at end of year	$3,458	$3,199
Determination of net recorded asset (liability)		
Funded status	$ 48	$ (219)
Unrecognized net loss	—	137
Unrecognized prior service cost	—	78
Net recorded asset (liability)	$ 48	$ (4)
Additional detail of amounts recognized in the consolidated balance sheets:		
Intangible asset	$ —	$ 3
Accumulated other comprehensive loss	46	24
Additional detail of amount recognized in accumulated other comprehensive loss:		
Prior service cost	$ 4	—
Net actuarial loss	42	—
Additional detail of amount recognized as a regulatory liability:		
Prior service cost	$ 71	—
Net actuarial loss (gain)	(215)	—
Pension plans with an accumulated benefit obligation in excess of plan assets:		
Projected benefit obligation	$ 232	$ 227
Accumulated benefit obligation	197	183
Fair value of plan assets	60	59
Weighted-average assumptions at end of year:		
Discount rate	5.75%	5.5%
Rate of compensation increase	5.0%	5.0%

Expense components are:

In millions Year ended December 31,	2006	2005	2004
Service cost	**$ 118**	$ 117	$ 103
Interest cost	**181**	175	171
Expected return on plan assets	**(232)**	(221)	(206)
Special termination benefits	**8**	—	—
Amortization of transition obligation	**—**	1	5
Amortization of unrecognized prior service cost	**16**	16	15
Amortization of unrecognized net loss	**6**	6	5
Expense under accounting standards	**97**	94	93
Regulatory adjustment – deferred	**(10)**	(26)	(26)
Total expense recognized	**$ 87**	$ 68	$ 67
Change in accumulated other comprehensive income (loss)	**$ (22)**	$ 4	$ (6)
Weighted-average assumptions:			
Discount rate	**5.5%**	5.5%	6.0%
Rate of compensation increase	**5.0%**	5.0%	5.0%
Expected return on plan assets	**7.5%**	7.5%	7.5%

The estimated amortization amounts for 2007 are $17 million for prior service cost and $5 million for net actuarial loss.

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

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

In millions Year ended December 31,	
2007	$ 268
2008	281
2009	294
2010	306
2011	323
2012 – 2016	1,655

Asset allocations are:

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

Postretirement Benefits Other Than Pensions

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

On December 8, 2003, President Bush signed the Medicare Prescription Drug, Improvement and Modernization Act of 2003. The Act authorized a federal subsidy to be provided to plan sponsors for certain prescription drug benefits under Medicare. Edison International adopted a new accounting pronouncement for the effects of the Act, effective July 1, 2004, which reduced Edison International's accumulated benefit obligation by $120 million upon adoption.

The expected contributions (all by the employer) to the PBOP trust are $42 million for the year ended December 31, 2007. This amount is subject to change based on, among other things, the limits established for federal tax deductibility.

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

Information on plan assets and benefit obligations is shown below:

In millions Year ended December 31,	2006	2005
Change in benefit obligation		
Benefit obligation at beginning of year	**$2,357**	$2,212
Service cost	**45**	46
Interest cost	**120**	123
Amendments	**—**	(15)
Actuarial loss (gain)	**(163)**	48
Special termination benefits	**4**	—
Plan participants' contributions	**7**	3
Medicare Part D subsidy received	**3**	—
Benefits paid	**(113)**	(60)
Benefit obligation at end of year	**$2,260**	$2,357
Change in plan assets		
Fair value of plan assets at beginning of year	**$1,573**	$1,465
Actual return on assets	**203**	92
Employer contributions	**70**	73
Plan participants' contributions	**7**	3
Medicare Part D subsidy received	**3**	—
Benefits paid	**(113)**	(60)
Fair value of plan assets at end of year	**$1,743**	$1,573
Determination of net recorded liability		
Funded status	**$ (517)**	$ (784)
Unrecognized net loss	**—**	869
Unrecognized prior service cost (credit)	**—**	(284)
Recorded asset (liability)	**$ (517)**	$ (199)
Additional detail of amounts recognized in accumulated other comprehensive loss (income):		
Prior service cost (credit)	**$ (11)**	—
Net actuarial loss	**19**	—
Additional detail of amounts recognized as a regulatory asset:		
Prior service cost (credit)	**$ (242)**	—
Net actuarial loss	**545**	—
Weighted-average assumptions at end of year:		
Discount rate	**5.75%**	5.5%
Assumed health care cost trend rates:		
Rate assumed for following year	**9.25%**	10.25%
Ultimate rate	**5.0%**	5.0%
Year ultimate rate reached	**2011**	2011

Expense components are:

In millions Year ended December 31,	2006	2005	2004
Service cost	**$ 45**	$ 46	$ 42
Interest cost	**120**	123	126
Expected return on plan assets	**(105)**	(101)	(96)
Special termination benefits	**4**	—	—
Amortization of unrecognized prior service cost (credit)	**(31)**	(30)	(31)
Amortization of unrecognized net loss	**43**	47	50
Total expense	**$ 76**	$ 85	$ 91
Weighted-average assumptions:			
Discount rate	**5.5%**	5.75%	6.25%
Expected return on plan assets	**7.0%**	7.1%	7.1%
Assumed health care cost trend rates:			
Current year	**10.25%**	10.0%	12.0%
Ultimate rate	**5.0%**	5.0%	5.0%
Year ultimate rate reached	**2011**	2010	2010

The estimated amortization amounts for 2007 are $(31) million for prior service cost (credit) and $26 million for net actuarial loss.

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

Increasing the health care cost trend rate by one percentage point would increase the accumulated benefit obligation as of December 31, 2006 by $281 million and annual aggregate service and interest costs by $19 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated benefit obligation as of December 31, 2006 by $250 million and annual aggregate service and interest costs by $17 million.

The following benefit payments are expected to be paid:

In millions Year ended December 31,	Before Subsidy	Net
2007	$102	$ 97
2008	102	97
2009	112	106
2010	121	115
2011	130	123
2012 – 2016	753	705

Asset allocations are:

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

Description of Pension and Postretirement Benefits Other Than Pensions Investment Strategies

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

Allowable investment types include:

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

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

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

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

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

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

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

Capital Markets Return Forecasts

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

Stock-Based Compensation

Stock Options

Under various plans, Edison International may grant stock options at exercise prices equal to the average of the high and low price at the grant date and other awards related to or with a value derived from its common stock to directors and certain employees. Options generally expire 10 years after the grant date and vest over a period of four years of continuous service, with expense recognized evenly over the requisite service period, except for awards granted to retirement-eligible participants, as discussed in "Stock-Based Compensation" in Note 1. Stock-based compensation associated with stock options (including amounts capitalized) was $41 million 2006. Under prior accounting rules, there was no comparable expense recognized for the same period in 2005 and 2004. See "Stock-Based Compensation" in Note 1 for further discussion.

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

International will substitute cash awards to the extent necessary to pay tax withholding or any government levies.

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

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

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

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

		Weighted-Average		
	Stock Options	Exercise Price	Remaining Contractual Term (Years)	Aggregate Intrinsic Value
Outstanding at December 31, 2005	15,331,659	$22.99		
Granted	2,026,168	$44.10		
Expired	—	—		
Forfeited	(123,889)	$34.89		
Exercised	(3,122,241)	$21.11		
Outstanding at December 31, 2006	14,111,697	$26.33		
Vested and expected to vest at December 31, 2006	13,510,948	$26.11	6.32	$223,190,052
Exercisable at December 31, 2006	7,086,788	$21.90	4.98	$146,903,446

The weighted-average grant-date fair value of options granted during 2006, 2005 and 2004 was $14.42, $11.82 and $8.25, respectively. The total intrinsic value of options exercised during 2006, 2005 and 2004 was $70 million, $77 million and $27 million, respectively. At December 31, 2006, there was $33 million of total unrecognized compensation cost related to stock options, net of expected forfeitures. That cost is expected to be recognized over a weighted-average period of approximately two years. The fair value of options vested during 2006, 2005 and 2004 was $45 million, $26 million and $18 million, respectively.

The amount of cash used to settle stock options exercised was $136 million, $162 million and $75 million for 2006, 2005, and 2004, respectively. Cash received from options exercised for 2006, 2005 and 2004 was $66 million, $85 million and $48 million, respectively. The estimated tax benefit from options exercised for 2006, 2005 and 2004 was $27 million, $30 million and $11 million, respectively.

In October 2001, a stock option retention exchange offer was extended offering holders of Edison International's stock options granted in 2000 the opportunity to exchange those options for a lesser number of deferred stock units, payable in shares of Edison International common stock. Approximately three options were cancelled for each deferred stock unit issued. The deferred stock units vested, and were settled, 25% in each of the ensuing 12-month periods. Cash used to settle deferred stock units in 2005 and 2004 was $20 million and $16 million, respectively.

Performance Shares

A target number of contingent performance shares were awarded to executives in January 2004, January 2005 and March 2006, and vest at the end of December 2006, 2007 and 2008, respectively. Dividend equivalents associated with these performance shares accumulate without interest and will be payable in cash following the end of the performance period when the performance shares are paid, although Edison International has discretion to pay certain dividend equivalents in Edison International common stock. The vesting of Edison International's performance shares is dependent upon a market condition and three years of continuous service subject to a prorated adjustment for employees who are terminated under certain circumstances or retire, but payment cannot be accelerated. The market condition is based on Edison International's common stock performance relative to the performance of a specified group of companies at the end of a three-calendar-year period. The number of performance shares earned is determined based on Edison International's ranking among these companies. Dividend equivalents will be adjusted to correlate to the actual number of performance shares paid. Performance shares earned are settled half in cash and half in common stock; however, Edison International has discretion under certain of the awards to pay the half subject to cash settlement in common stock. Additionally, cash awards are substituted to the extent necessary to pay tax withholding or any government levies. The portion of performance shares settled in cash is classified as a share-based liability award. The fair value of these shares is remeasured at each reporting period and the related compensation expense is adjusted. The portion of performance shares payable in common stock is classified as a share-based equity award. Compensation expense related to these shares is based on the grant-date fair value. Performance shares expense is recognized ratably over the requisite service period based on the fair values determined, except for awards granted to retirement-eligible participants, as discussed in "Stock-Based Compensation" in Note 1. Stock-based compensation associated with performance shares (including amounts capitalized) was $16 million, $59 million and $63 million for 2006, 2005 and 2004, respectively. The amount of cash used to settle performance shares classified as equity awards was $37 million, $3 million and $17 million for 2006, 2005 and 2004, respectively.

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

Edison International's risk-free interest rate used to determine the grant date fair values for the 2006, 2005 and 2004 performance shares classified as share-based equity awards was 4.1%, 2.7% and 2.1%, respectively. Edison International's expected volatility used to determine the grant date fair values for the 2006, 2005 and 2004 performance shares classified as share-based equity awards was 16.2%, 27.7% and 36.0%, respectively. The portion of performance shares classified as share-based liability awards are revalued at each reporting period. The risk-free interest rate and expected volatility rate used to determine the fair value as of December 31, 2006 was 4.8% and 16.5%, respectively.

The total intrinsic value of performance shares settled during 2006, 2005 and 2004 was $73 million, $40 million and $8 million, respectively, which included cash paid to settle the performance shares classified as liability awards for 2006, 2005 and 2004 of $24 million, $13 million and $4 million, respectively. At December 31, 2006, there was $6 million (based on the December 31, 2006 fair value of performance shares classified as liability awards) of total unrecognized compensation cost related to performance shares. That cost is expected to be recognized over a weighted-average period of less than two years. The fair value of performance shares vested during 2006, 2005 and 2004 was $27 million, $42 million and $26 million, respectively.

A summary of the status of Edison International nonvested performance shares classified as equity awards is as follows:

	Performance Shares	Weighted-Average Grant-Date Fair Value
Nonvested at December 31, 2005	280,289	$39.19
Granted	83,008	$52.90
Forfeited	(6,050)	$41.75
Paid out	(154,633)	$33.82
Nonvested at December 31, 2006	202,614	$48.83

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

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

	Performance Shares	Weighted-Average Fair Value
Nonvested at December 31, 2005	280,434	
Granted	83,096	
Forfeited	(6,061)	
Paid out	(154,700)	
Nonvested at December 31, 2006	202,769	$49.83

Note 6. Commitments and Contingencies

Lease Commitments

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

During 2001, a subsidiary of 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 a fair value of $809 million). Under the terms of the 33.67-year leases, EME's subsidiary is obligated to make semi-annual lease payments. If a lessor intends to sell its interest in the Homer City facilities, EME has a right of first refusal to acquire the interest at fair market value.

During 2000, a subsidiary of EME entered into a sale-leaseback transaction for power facilities, located in Illinois, with third party lessors for an aggregate purchase price of $1.4 billion. Under the terms of the leases (33.75 years for one facility and 30 years for the other), EME's subsidiary makes semi-annual lease payments. EME's guarantees its subsidiary's payments under the leases. If a lessor intends to sell its interest in either facility, EME has a right of first refusal to acquire the interest at fair market value.

Edison International has other operating leases for office space, vehicles, property and other equipment (with varying terms, provisions and expiration dates). Estimated remaining commitments (the majority of other operating leases are related to EME's long-term leases for the Illinois power facilities and Homer City facilities discussed above) for noncancelable operating leases at December 31, 2006 are:

In millions	Year ended December 31,	Power Contracts Operating Leases	Other Operating Leases
2007		$ 579	$ 399
2008		556	395
2009		499	386
2010		463	368
2011		254	344
Thereafter		1,669	2,742
Total		**$4,020**	**$4,634**

The minimum commitments above do not include EME's contingent rentals with respect to the wind projects which may be paid under certain leases on the basis of a percentage of sales calculation if this is in excess of the stipulated minimum amount.

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

Operating lease expense was $420 million in 2006, $289 million in 2005 and $228 million in 2004.

Nuclear Decommissioning Commitment

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

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

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

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

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

Trust investments (at fair value) include:

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

Note: Maturity dates as of December 31, 2006.

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

Other Commitments

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

In February 2007, EME contracted for the purchase of additional coal in the amount of nine million tons for 2008, six million tons for 2009 and six million tons for 2010.

At December 31, 2006, EME had a contractual commitment to transport natural gas. EME is committed to pay minimum fees under this agreement, which has a remaining contract length of 11 years.

At December 31, 2006, EME's subsidiaries had contractual commitments for the transport of coal to their respective facilities, with remaining contract lengths that range from one year to five years. EME is committed to pay minimum fees under these agreements.

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

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

In millions	2007	2008	2009	2010	2011
Fuel supply	$440	$224	$140	$115	$ 63
Gas and coal transportation payments	228	92	83	84	8
Purchased power	481	255	144	134	112

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

At December 31, 2006, EME's subsidiaries had firm commitments to spend approximately $186 million in 2007 on capital and construction expenditures. The majority of these expenditures relate to the construction of the 161-MW Wildorado wind project (see further discussion related to the Wildorado project in Note 19, Acquisitions and Dispositions) and four other wind projects totaling 181 MW. Also included are expenditures for dust collection and mitigation system and various other smaller projects. These expenditures are planned to be financed by cash on hand, cash generated from operations or existing subsidiary credit agreements.

At December 31, 2006, EME had entered into agreements with vendors securing 255 wind turbines (487 MW) with remaining commitments of $387 million in 2007 and $23 million in 2008. In addition, EME had entered into an agreement for the purchase of five gas turbines and related equipment for an aggregate purchase price of approximately $140 million with remaining commitments of $76 million in 2007 and $3 million in 2008. In February 2007, EME was advised that it was an unsuccessful bidder in the request for offers conducted by SCE for the supply of generation capacity. EME plans to use the turbines which it had purchased and reserved for this bid for other generation supply opportunities.

At December 31, 2006, Midwest Generation was party to a long-term power purchase contract with Calumet Energy Team LLC entered into as part of the settlement agreement with Commonwealth Edison, which terminated Midwest Generation's obligation to build additional gas-fired generation in the Chicago area. The contract requires Midwest Generation to pay a monthly capacity payment and gives Midwest Generation an option to purchase energy from Calumet Energy Team at prices based primarily on operations and maintenance and fuel costs. These minimum commitments are estimated to aggregate $17 million in the next five years: $4 million each year, 2007 to 2010 and less than $1 million in 2011.

Guarantees and Indemnities

Edison International's subsidiaries have various financial and performance guarantees and indemnifications which are issued in the normal course of business. As discussed below, these contracts included performance guarantees, guarantees of debt and indemnifications.

Tax Indemnity Agreements

In connection with the sale-leaseback transactions that EME has entered into related to the Collins Station in Illinois, the Powerton and Joliet Stations in Illinois and the Homer City facilities in Pennsylvania, EME and several of its subsidiaries entered into tax indemnity agreements. Under these tax indemnity agreements, these entities 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 potential obligations, EME cannot determine a maximum potential liability which would be triggered by a valid claim from the lessors. EME has not recorded a liability related to these indemnities. In connection with the termination of the Collins Station lease in 2004, Midwest Generation will continue to have obligations under the tax indemnity agreement with the former lease equity investor. For more information about the termination of the Collins Station lease, see "Loss on Lease Termination" in Note 21.

Indemnities Provided as Part of EME's Acquisition of the Illinois Plants

In connection with the acquisition of the Illinois plants, EME agreed to indemnify Commonwealth Edison with respect to specified environmental liabilities before and after December 15, 1999, the date of sale. The indemnification claims are reduced by any insurance proceeds and tax benefits related to such claims and are subject to a requirement that Commonwealth Edison takes all reasonable steps to mitigate losses related to any such indemnification claim. Due to the nature of the obligation under this indemnity, a maximum potential liability cannot be determined. This indemnification for environmental liabilities is not limited in term and would be triggered by a valid claim from Commonwealth Edison. Except as discussed below, EME has not recorded a liability related to this indemnity.

Midwest Generation entered into a supplemental agreement with Commonwealth Edison and Exelon Generation on February 20, 2003 to resolve a dispute regarding interpretation of its reimbursement obligation for asbestos claims under the environmental indemnities set forth in the asset sale agreement. Under this supplemental agreement, Midwest Generation agreed to reimburse Commonwealth Edison and Exelon Generation for 50% of specific asbestos claims pending as of February 2003 and related expenses less recovery of insurance costs, and agreed to a sharing arrangement for liabilities and expenses associated with future asbestos-related claims as specified in the agreement. As a general matter, Commonwealth Edison and Midwest Generation apportion responsibility for future asbestos-related claims based upon the number of exposure sites that are Commonwealth Edison locations or Midwest Generation locations. 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 of either party to terminate). Payments are made under this indemnity upon tender by Commonwealth Edison of appropriate proof of liability for an asbestos-related settlement, judgment, verdict, or expense. There were approximately 186 cases for which Midwest Generation was potentially liable and that had not been settled and dismissed at December 31, 2006. Midwest Generation had recorded a $65 million and $67 million liability at December 31, 2006 and 2005, respectively, related to this matter.

The amounts recorded by Midwest Generation for the asbestos-related liability are based upon a number of assumptions. Future events, such as the number of new claims to be filed each year, the average cost of disposing of claims, as well as the numerous uncertainties surrounding asbestos litigation in the United States, could cause the actual costs to be higher or lower than projected.

Indemnity Provided as Part of EME's Acquisition of the Homer City Facilities

In connection with the acquisition of the Homer City facilities, EME Homer City agreed to indemnify the sellers with respect to specific environmental liabilities before and after the date of sale. Payments would be triggered under this indemnity by a claim from the sellers. EME guaranteed the obligations of EME Homer City. Due to the nature of the obligation under this indemnity provision, it is not subject to a maximum potential liability and does not have an expiration date. EME has not recorded a liability related to this indemnity.

Indemnities Provided Under Asset Sale Agreements

The asset sale agreements for the sale of EME's international assets contain indemnities from EME to the purchasers, including indemnification for taxes imposed with respect to operations of the assets prior to the sale and for pre-closing environmental liabilities. Not all indemnities under the asset sale agreements have specific expiration dates. Payments would be triggered under these indemnities by valid claims from the sellers or purchasers, as the case may be. At December 31, 2006 and 2005, EME had recorded a liability of $95 million and $122 million, respectively, related to these matters.

In connection with the sale of various domestic assets, EME has from time to time provided indemnities to the purchasers for taxes imposed with respect to operations of the asset prior to the sale. EME has 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. Not all indemnities under the asset sale agreements 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.

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 agreements terminate, 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 sales agreements. In addition, a subsidiary of EME has guaranteed the obligations of Sycamore Cogeneration Company under its project power sales agreement to repay capacity payments to the project's power purchaser in the event that the project unilaterally terminates its performance or reduces its electric power producing capability during the term of the power sales agreements. The obligations under the indemnification agreements as of December 31, 2006, if payment were required, would be $101 million. EME has not recorded a liability related to these indemnities.

Indemnity Provided as Part of the Acquisition of Mountainview

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

Other Edison International Indemnities

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

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.

2006 General Rate Case Proceeding

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

During the second quarter of 2006, SCE implemented the 2006 GRC decision and resolved an outstanding regulatory issue which resulted in a pre-tax benefit of approximately $175 million. The implementation of the

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

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 the 35 identified sites at SCE (23 sites) and EME (12 sites related to Midwest Generation) is $81 million, $78 million of which is related to SCE. 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 the recorded liability by up to $123 million, all 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. In addition to the identified sites (sites in which the upper end of the range of costs is at least $1 million), SCE also has 32 immaterial sites whose total liability ranges from $3 million (the recorded minimum liability) to $8 million.

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

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 the identified sites over a period of up to 30 years. Remediation costs in each of the next several years are expected to range from $11 million to $25 million. Recorded costs for 2006 were $14 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 the 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 and State Income Taxes

Edison International received Revenue Agent Reports from the IRS in August 2002 and in January 2005 asserting deficiencies in federal corporate income taxes with respect to audits of its 1994 – 1996 and 1997 – 1999 tax years, respectively. Edison International expects to conclude the administrative phase of the 1994 – 1996 tax years during the first half of 2007. Many of the asserted tax deficiencies are timing differences and, therefore, amounts ultimately paid (exclusive of penalties), if any, would be deductible on future tax returns of Edison International. Edison International has also submitted affirmative claims to the IRS and state tax agencies which are being addressed in administrative proceedings. Any benefits would be recorded at the earlier of when Edison International believes that the affirmative claim position has a more likely than not probability of being sustained or when a settlement is reached. Certain affirmative claims may be recorded as part of the implementation of FIN 48.

As part of a nationwide challenge of certain types of lease transactions, the IRS has raised issues about the deferral of income taxes associated with Edison Capital's cross-border, leveraged leases.

The IRS is challenging Edison Capital's foreign power plant and electric locomotive sale/leaseback transactions entered into in 1993 and 1994 (Replacement Leases, which the IRS refers to as a sale-in/lease-out or SILO). The IRS is also challenging Edison Capital's foreign power plant and electric transmission system lease/leaseback transactions entered into in 1997 and 1998 (Lease/Leaseback, which the IRS refers to as a lease-in/lease-out or LILO).

Edison Capital also entered into a lease/service contract transaction in 1999 involving a foreign telecommunication system (Service Contract, which the IRS also refers to as a SILO). The IRS has not yet asserted any adjustment for the Service Contract but the IRS has submitted data requests to Edison International regarding the issue as part of the IRS examination of tax years 2000 – 2002.

The following table summarizes estimated federal and state income taxes deferred from these leases. Repayment of these deferred taxes would be accelerated if the IRS prevails:

In millions	Tax Years Under Appeal 1994 – 1999	Tax Years Under Audit 2000 – 2002	Unaudited Tax Years 2003 – 2006	Total
Replacement Leases (SILO)	$ 44	$ 19	$ 23	$ 86
Lease/Leaseback (LILO)	558	562	6	1,126
Service Contract (SILO)	—	126	199	325
	$602	$707	$228	$1,537

As of December 31, 2006, the interest on the proposed tax adjustments is estimated to be approximately $417 million. The IRS also seeks a 20% penalty on any sustained tax adjustment.

Edison International believes it properly reported these transactions based on applicable statutes, regulations and case law in effect at the time the transactions were entered into, and it is vigorously defending its tax treatment of these leases. Written protests were filed to appeal the audit adjustments for the tax years under appeal asserting that the IRS's position misstates material facts, misapplies the law and is incorrect. This matter is now being considered by the Administrative Appeals branch of the IRS.

In addition, the payment of taxes, interest and penalties could have a significant impact on earnings and cash flow. In order to commence litigation in certain forums, Edison International must make payments of disputed taxes, along with interest and any penalties asserted by the IRS, and thereafter pursue refunds. On May 26, 2006, Edison International paid $111 million of the taxes, interest and penalties for tax year 1999 followed by a refund claim for the same amount. The cash payment was funded by Edison Capital and accounted for as a deposit which will be refunded with interest to the extent Edison International prevails. Since the IRS did not act on this refund claim within six months from the date the claim was filed, it is deemed denied. Edison International expects to take legal action to assert its refund claim.

A number of other cases involving these kinds of lease transactions are pending before various courts. The first case involving a LILO was recently decided against the taxpayer on summary judgment in the Federal District Court in North Carolina. That taxpayer has announced its intention to appeal that decision to the Fourth Circuit Court of Appeals.

Edison International expects to file a refund claim for any taxes and penalties paid pursuant to the administrative appeals settlement of the 1994 – 1996 tax years related to assessed tax deficiencies and penalties on the Replacement Leases. These payments would be treated as a deposit. Edison International may make additional payments related to other tax years to preserve its litigation rights, although, at this time, the amount and timing of these additional payments is uncertain. At this time, Edison International is unable to predict the impact of the ultimate resolution of these matters.

Under FSP FAS 13-2 related to accounting for a change or projected change in the timing of cash flows relating to income taxes generated by a leveraged lease transaction and FIN 48 relating to accounting for uncertainty in income taxes, both issued in July 2006 and effective January 1, 2007, the payments made by Edison International will continue to be treated as a deposit unless it becomes more likely than not that a tax payment related to the resolution of the dispute will be made. If this occurs, the new FSP requires the change in the timing of cash flows to trigger a recalculation of the income allocated over the life of the lease, with the cumulative effect of the change recognized immediately. This could result in a material charge against earnings, although future income would be expected to increase over the remaining terms of the affected leases.

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

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

In December 2006, Edison International reached a settlement with the California Franchise Tax Board regarding the sourcing of gross receipts from the sale of electric services for California state tax apportionment purposes for tax years 1981 to 2004. In the fourth quarter of 2006, Edison International recorded a $49 million benefit related to a tax reserve adjustment as a result of this settlement. In addition to this tax reserve adjustment, Edison International expects to receive a net cash refund of approximately $49 million in the first half of 2007 as a result of this settlement.

FERC Notice Regarding Investigatory Proceeding against EMMT

At the end of October 2006, EMMT was advised by the enforcement staff at the FERC that it is prepared to recommend that the FERC initiate a formal investigatory proceeding and seek monetary sanctions against EMMT for alleged violation of the FERC's rules with respect to certain bidding practices employed by

EMMT. EMMT is engaged in discussions with the staff to explore the possibility of resolution of this matter. Should a formal proceeding be commenced, EMMT will be entitled to contest any alleged violations before the FERC and an appropriate court. EME believes that EMMT has complied with the FERC's rules and intends to contest vigorously any allegation of violation. EME cannot predict at this time the outcome of this matter or estimate the possible liability should the outcome be adverse.

FERC Refund Proceedings

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

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

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

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

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

Investigations Regarding Performance Incentives Rewards

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

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

<u>Customer Satisfaction</u>

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

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

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

Employee Injury and Illness Reporting

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

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

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

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

CPUC Investigation

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

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

ISO Disputed Charges

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

Leveraged Lease Investments

Edison Capital has a net leveraged lease investment of $56 million, before deferred taxes, in three aircraft leased to American Airlines. Although American Airlines has reported a profit in 2006, it has reported net losses for a number of years prior to 2006. A default in the leveraged lease by American Airlines could result in a loss of some or all of Edison Capital's lease investment. At December 31, 2006, American Airlines was current in its lease payments to Edison Capital.

Edison Capital also has a net leveraged lease investment of $43 million, before deferred taxes, in a 1,500-MW natural gas-fired cogeneration plant leased to Midland Cogen. During 2005, Midland Cogen wrote down the book value of its power plant as a result of substantial increases in long-term natural gas prices. A default of the lease could result in a loss of some or all of Edison Capital's lease investment. At December 31, 2006, Midland Cogen was current in its payments under the lease.

Midway-Sunset Cogeneration Company

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

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

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

Navajo Nation Litigation

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

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

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

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

Nuclear Insurance

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

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

Procurement of Renewable Resources

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

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

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

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

Scheduling Coordinator Tariff Dispute

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

Settlement Agreement with Duke Energy Trading and Marketing, LLC

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

Spent Nuclear Fuel

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

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

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

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

Note 7. Accumulated Other Comprehensive Income (Loss)

Edison International's accumulated other comprehensive income (loss), including discontinued operations, consists of:

In millions December 31,	**2006**	2005
Foreign currency translation adjustments – net of tax	**$ 1**	$ 2
Minimum pension liability – net of tax	**—**	(12)
SFAS No. 158 – postretirement benefits – net of tax	**(33)**	—
Unrealized gains (losses) on cash flow hedges – net of tax	**110**	(216)
Accumulated other comprehensive income (loss)	**$ 78**	$(226)

SFAS No. 158 – postretirement benefits is discussed in "Pension Plans and Postretirement Benefits Other Than Pensions" in Note 5.

Included in Edison International's accumulated other comprehensive income at December 31, 2006, was a $110 million unrealized gain related to EME's cash flow hedges.

Unrealized gains on cash flow hedges at December 31, 2006, include unrealized gains on commodity hedges related to EME Homer City and Midwest Generation futures and forward electricity contracts that qualify for hedge accounting. These gains arise because current forecasts of future electricity prices in these markets are lower than the contract prices. The change from unrealized losses to unrealized gains during 2006 resulted from a decrease in market prices for power and hedge contracts that settled during 2006.

As EME's hedged positions for continuing operations are realized, approximately $94 million (after tax) of the net unrealized gains on cash flow hedges at December 31, 2006 are expected to be reclassified into earnings during 2007. EME expects that reclassification of net unrealized gains will offset energy revenue recognized at market prices. 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. The maximum period over which an EME cash flow hedge is designated is through December 31, 2009.

Under SFAS No. 133, the portion of a cash flow hedge that does not offset the change in value of the transaction being hedged (the ineffective portion) is immediately recognized in earnings. EME recorded net losses of approximately $6 million, $65 million and $13 million in 2006, 2005 and 2004, respectively, representing the amount of cash flow hedges' ineffectiveness for continuing operations. These amounts are reflected in nonutility power generation revenue on Edison International's consolidated statements of income.

Note 8. Property and Plant

Nonutility Property

Nonutility property included on the consolidated balance sheets is composed of:

In millions December 31,	**2006**	2005
Furniture and equipment	**$ 107**	$ 102
Building, plant and equipment	**4,026**	3,663
Land (including easements)	**78**	78
Emission allowances	**1,305**	1,305
Leasehold improvements	**100**	90
Construction in progress	**367**	305
	5,983	5,543
Accumulated provision for depreciation	**(1,627)**	(1,424)
Nonutility property—net	**$ 4,356**	$ 4,119

Asset Retirement Obligations

As a result of the adoption of SFAS No. 143 in 2003, Edison International recorded the fair value of its liability for legal AROs, which was primarily related to the decommissioning of SCE's nuclear power facilities. In addition, SCE capitalized the initial costs of the ARO into a nuclear-related ARO regulatory asset, and also recorded an ARO regulatory liability as a result of timing differences between the recognition of costs recorded in accordance with the standard and the recovery of the related asset retirement costs through the rate-making process. SCE has collected in rates amounts for the future costs of removal of its nuclear assets, and has placed those amounts in independent trusts. For a further discussion about nuclear decommissioning trusts see "Nuclear Decommissioning Commitment" in Note 6.

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

In millions	**2006**	2005	2004
Beginning balance	**$2,628**	$2,188	$2,089
Accretion expense	**160**	366	132
Revisions	**—**	117	—
Liabilities added	**42**	16	—
Liabilities settled	**(71)**	(59)	(33)
Ending balance	**$2,759**	$2,628	$2,188

The fair value of the nuclear decommissioning trusts was $3.2 billion at December 31, 2006.

In March 2005, the FASB issued FIN 47, which clarifies that an entity is required to recognize a liability for the fair value of a conditional ARO if the fair value can be reasonably estimated even though uncertainty exists about the timing and/or method of settlement. FIN 47 was effective as of December 31, 2005. Due to the adoption of FIN 47 in 2005, Edison International recorded a cumulative effect adjustment that decreased net income by approximately $1 million, net of tax. The cumulative effect adjustment in 2005 was the result of EME's adoption of FIN 47. SCE follows accounting principles for rate-regulated enterprises and receives recovery of these costs through rates; therefore, SCE's implementation of FIN 47 did not affect Edison International's earnings.

Pro forma disclosures related to adoption of FIN 47 are not shown due to their immaterial impact on Edison International.

Note 9. Supplemental Cash Flow Information

Edison International's supplemental cash flows information is:

In millions Year ended December 31,	**2006**	2005	2004
Cash payments for interest and taxes:			
Interest – net of amounts capitalized	**$ 739**	$ 776	$ 878
Tax payments (receipts) – net	**826**	185	(33)
Noncash investing and financing activities:			
Details of debt exchange:			
Pollution-control bonds redeemed	**$(331)**	$(452)	—
Pollution-control bonds issued	**331**	452	—
Dividends declared but not paid	**$ 94**	$ 88	$ 81
Details of assets acquired:			
Fair value of assets acquired	**$ 29**	$ 154	—
Liabilities assumed	**—**	—	—
Net assets acquired	**$ 29**	$ 154	—
Details of capital lease obligation:			
Capital lease purchased	**—**	$ (15)	—
Capital lease obligation issued	**—**	15	—
Details of consolidation of variable interest entities:			
Assets	**$ 18**	$ 37	$ 625
Liabilities	**(4)**	(27)	(704)
Details of deconsolidation of variable interest entities:			
Assets	**—**	—	$(220)
Liabilities	**—**	—	254
Reoffering of pollution-control bonds	**—**	—	$ 196
Details of pollution-control bond redemption:			
Release of funds held in trust	**—**	—	$ 20
Pollution-control bonds issued	**—**	—	(20)

During the year ended December 31, 2006, EME accrued $11 million in connection with the purchase price of the Wildorado wind project due upon completion of construction.

Note 10. Fair Values of Financial Instruments

The carrying amounts and fair values of financial instruments are:

	December 31,			
	2006		2005	
In millions	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Derivatives:				
Interest rate hedges	**$ 5**	**$ 5**	$ (12)	$ (12)
Commodity price assets	**234**	**234**	239	239
Commodity price liabilities	**(160)**	**(160)**	(521)	(521)
Other:				
Decommissioning trusts	**3,184**	**3,184**	2,907	2,907
DOE decommissioning and decontamination fees	**—**	**—**	(7)	(7)
QF power contracts assets	**—**	**—**	23	23
QF power contracts liabilities	**(2)**	**(2)**	(94)	(94)
Long-term debt	**(9,101)**	**(9,607)**	(8,833)	(9,511)
Long-term debt due within one year	**(488)**	**(488)**	(745)	(763)
Trading Activities:				
Assets	**318**	**318**	128	128
Liabilities	**(207)**	**(207)**	(27)	(27)

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

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 nonrecourse debt incurred to finance the purchase of the power supply agreement.

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

Note 11. Regulatory Assets and Liabilities

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

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

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

Regulatory Assets

Regulatory assets included on the consolidated balance sheets are:

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

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

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

Regulatory Liabilities

Regulatory liabilities included on the consolidated balance sheets are:

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

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

Note 12. Other Nonoperating Income and Deductions

Other nonoperating income and deductions are as follows:

In millions Year ended December 31,	2006	2005	2004
AFUDC	**$ 32**	$ 25	$ 35
Performance-based incentive awards	**19**	33	31
Demand-side management and energy efficiency performance incentives	**—**	45	—
Other	**34**	24	18
Total utility nonoperating income	**85**	127	84
Nonutility nonoperating income	**48**	9	51
Total other nonoperating income	**$133**	$136	$135
Various penalties	**$ 23**	$ 27	$ 35
Other	**37**	38	34
Total utility nonoperating deductions	**60**	65	69
Nonutility nonoperating deductions	**3**	2	11
Total other nonoperating deductions	**$ 63**	$ 67	$ 80

In 2006, nonutility nonoperating income primarily reflects Edison Capital's $19 million pre-tax gain on the sale of certain investments, the recognition at EME of an estimated business interruption insurance claim of $11 million and EME's $8 million gain related to the receipt of shares from Mirant Corporation from settlement of a claim recorded during the first quarter of 2006. In 2004, nonutility nonoperating income reflects EME's pre-tax gain of $47 million on the sale of its interest in Four Star Oil & Gas.

Note 13. Jointly Owned Utility Projects

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

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

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

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

Note 14. Variable Interest Entities

Entities Consolidated

SCE has variable interests in contracts with certain QFs that contain variable contract pricing provisions based on the price of natural gas. Four of these contracts are with entities that are partnerships owned in part by a related party, EME. These four contracts had 20-year terms at inception. The QFs sell electricity to SCE and steam to nonrelated parties. Under FIN 46(R), Edison International and SCE consolidated these four projects effective March 31, 2004. Prior periods have not been restated.

The book value of the projects' plant assets (recorded in nonutility property) is $319 million at December 31, 2006 and $345 million at December 31, 2005.

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

SCE has no investment in, nor obligation to provide support to, these entities other than its requirement to make contract payments. Any liabilities of these projects are nonrecourse to SCE.

Effective April 1, 2004, VIEs' operating costs are shown in Edison International's consolidated statements of income. Prior to that date, purchases under these QF contracts were reported as purchased-power expense. Further, Edison International's electric utility revenue includes revenue from the sale of steam by these four projects, beginning April 1, 2004.

Effective March 31, 2004, Edison Capital consolidated two affordable housing partnerships and three wind projects, and at December 31, 2005, Edison Capital consolidated two additional wind projects in accordance with FIN 46(R). Currently, Edison Capital has investments in affordable housing projects that are variable interests. These projects are funded with nonrecourse debt totaling $15 million at December 31, 2006. Properties serving as collateral for these loans had a carrying value of $15 million and are classified as nonutility property on the December 31, 2006 consolidated balance sheet. The creditors to these projects do not have recourse to the general credit of Edison Capital.

Currently, EME has investments in five wind projects that are variable interests. EME received ownership interests in the five wind projects previously consolidated by Edison Capital as part of Edison Capital's April 1, 2006 capital contribution (see "Basis of Presentation" in Note 1 for further information). These five wind projects were funded with nonrecourse debt totaling $27 million at December 31, 2006. Properties serving as collateral for these loans had a carrying value of $56 million and are classified as nonutility property on the December 31, 2006 consolidated balance sheet.

Wildorado Wind, L.P. is a special purpose entity formed to develop the Wildorado project, a planned 161-MW wind power generating facility to be located in Texas. A subsidiary of EME entered into a loan agreement with Wildorado Wind to fund turbine payments for the Wildorado project. In accordance with FIN 46(R), EME determined that it was the primary beneficiary and accordingly, consolidated Wildorado Wind at December 31, 2005. On January 5, 2006, EME completed the purchase of development rights for the Wildorado wind project. See "Acquisitions" in Note 19 for further discussion.

U.S. Wind Force is a development stage enterprise formed to develop wind projects in West Virginia, Pennsylvania and Maryland. In December 2006, a subsidiary of EME entered into a loan agreement with U.S. Wind Force to fund the redemption of a membership interest held by another party, repayment of loans, distributions to equity holders and to fund future development of wind projects. In accordance with FIN 46(R), EME is the primary beneficiary and, accordingly, consolidated U.S. Wind Force at December 15, 2006. The assets consolidated included $17 million of intangible assets, primarily related to project development rights, and are classified as part of other long-term assets in the consolidated balance sheet. As project development is completed, the project development rights will be considered part of nonutility property and depreciated over the estimated useful lives of the respective projects.

Entities Deconsolidated Upon Implementation of FIN 46(R)

EME deconsolidated the Doga and Kwinana projects effective March 31, 2004. The Kwinana project was sold on December 16, 2004, as part of EME's sale of its international operations and, accordingly, is included in discontinued operations.

Significant Variable Interests in Entities Not Consolidated

EME has a significant variable interest in the Sunrise project, which is a gas-fired facility located in California. As of December 31, 2006, EME had a 50% ownership interest in the project and its investment was $118 million. EME's maximum exposure to loss is generally limited to its investment in this entity.

Edison Capital's maximum exposure to loss from affordable housing investments in this category is generally limited to its net investment balance of $29 million and recapture of tax credits.

Entities with Unavailable Financial Information

SCE has eight nonrelated-party contracts with QFs that contain variable pricing provisions based on the price of natural gas and are potential VIEs. SCE might be considered to be the consolidating entity under FIN 46(R). However, these entities are not legally obligated to provide the financial information to SCE that is necessary to determine whether SCE must consolidate these entities. These eight entities have declined to provide SCE with the necessary financial information. SCE is continuing to attempt to obtain information for these projects in order to determine whether they should be consolidated by SCE. The aggregate capacity dedicated to SCE for these projects is 267 MW. SCE paid $180 million in 2006, $198 million in 2005 and $166 million in 2004 to these projects. These amounts are recoverable in utility customer rates. SCE has no exposure to loss as a result of its involvement with these projects.

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

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

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

SCE's preferred and preference stock not subject to mandatory redemption is:

Dollars in millions, except per-share amounts	December 31, 2006 Shares Outstanding	December 31, 2006 Redemption Price	**2006**	2005
Cumulative preferred stock				
$25 par value:				
4.08% Series	1,000,000	$ 25.50	**$ 25**	$ 25
4.24	1,200,000	25.80	**30**	30
4.32	1,653,429	28.75	**41**	41
4.78	1,296,769	25.80	**33**	33
Preference stock				
No par value:				
5.349% Series A	4,000,000	100.00	**400**	400
6.125% Series B	2,000,000	100.00	**200**	200
6.00% Series C	2,000,000	100.00	**200**	—
			929	729
Less issuance costs			**(14)**	(10)
Total			**$915**	$719

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

At December 31, 2006, accrued dividends related to SCE's preferred and preference stock not subject to mandatory redemption were $9 million.

Note 16. Mohave Shutdown

Mohave obtained all of its coal supply from the Black Mesa Mine in northeast Arizona, located on lands of the Tribes. This coal was delivered from the mine to Mohave by means of a coal slurry pipeline, which required water from wells located on lands belonging to the Tribes in the mine vicinity. Uncertainty over post-

2005 coal and water supply has prevented SCE and other Mohave co-owners from making approximately $1.1 billion in Mohave-related investments (SCE's share is $605 million), including the installation of enhanced pollution-control equipment required by a 1999 air-quality consent decree in order for Mohave to operate beyond 2005. Accordingly, the plant ceased operations, as scheduled, on December 31, 2005, consistent with the provisions of the consent decree.

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

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

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

Note 17. Business Segments

Edison International's reportable business segments include its electric utility operation segment (SCE), a nonutility power generation segment (MEHC – parent only and EME), and a financial services provider segment (Edison Capital). 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. MEHC, through its ownership of EME and its subsidiaries, is engaged in the business of developing, acquiring, owning or leasing, operating and selling energy and capacity from electric power generation facilities. Through EME, MEHC also conducts hedging and energy trading activities in power markets open to competition. Edison Capital is a provider of financial services with investments worldwide.

On April 1, 2006, EME received, as a capital contribution, ownership interests in a portfolio of wind projects located in Iowa and Minnesota and a small biomass project. As a result of this capital contribution, Edison International's nonutility power generation segment now includes the wind assets and biomass power project previously owned by Edison Capital. As a result of the change in the structure of Edison International's internal organization and in accordance with SFAS No. 131, Disclosures about Segments of an Enterprise and Related Information, prior periods have been restated to conform to Edison International's new business segment definition.

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

EME derived a significant source of its nonutility power generation revenue from electric power generally sold into the PJM market by participating in PJM's capacity and energy markets or transact capacity and energy on a bilateral basis. Sales into PJM accounted for approximately $1.3 billion in 2006, $1.6 billion in 2005 and $376 million in 2004 of EME's nonutility power generation revenue.

In 2004, EME also derived a significant source of its revenue from the sale of energy and capacity generated at the Illinois plants to Exelon Generation primarily under three power purchase agreements. These power purchase agreements had all expired by the end of 2004. Revenue from such sales was $586 million in 2004.

For the year ended December 31, 2004, approximately $241 million of EME's nonutility power generation revenue was from sales to BP Energy Company, a third-party customer. An investment grade affiliate of BP Energy has guaranteed payment of amounts due under the related contracts.

Reportable Segments Information

Information (including the elimination of intercompany transactions) related to Edison International's reportable segments is:

In millions	Electric Utility	Nonutility Power Generation	Financial Services	All Others[(1)]	Edison International
2006					
Operating revenue	$10,312	$2,232	$ 73	$ 5	$12,622
Depreciation, decommissioning and amortization	1,026	143	13	(1)	1,181
Interest income	51	96	19	3	169
Equity in income from partnerships and unconsolidated subsidiaries – net	—	50	29	—	79
Interest expense – net of amounts capitalized	400	393	16	(2)	807
Income tax expense (benefit) – continuing operations	438	145	11	(12)	582
Income (loss) from continuing operations	776	246	89	(28)	1,083
Net income (loss)	776[(2)]	344	89	(28)	1,181
Total assets	26,110	7,042	3,197	(88)	36,261
Capital expenditures	2,226	310	—	—	2,536
2005					
Operating revenue	$ 9,500	$2,265	$ 78	$ 9	$11,852
Depreciation, decommissioning and amortization	915	133	13	—	1,061
Interest income	38	59	11	4	112
Equity in income from partnerships and unconsolidated subsidiaries – net	—	63	73	—	136
Interest expense – net of amounts capitalized	360	414	22	(2)	794
Income tax expense (benefit) – continuing operations	292	156	10	(1)	457
Income (loss) from continuing operations	725	332	81	(30)	1,108
Net income (loss)	725[(2)]	360	81	(29)	1,137
Total assets	24,703	6,874	3,373	(159)	34,791
Capital expenditures	1,808	60	—	—	1,868
2004					
Operating revenue	$ 8,448	$1,653	$ 88	$ 10	$10,199
Depreciation, decommissioning and amortization	860	151	12	(1)	1,022
Interest income	15	8	10	13	46
Equity in income from partnerships and unconsolidated subsidiaries – net	—	79	9	(22)	66
Interest expense – net of amounts capitalized	409	456	27	93	985
Income tax expense (benefit) – continuing operations	438	(468)	(7)	(55)	(92)
Income (loss) from continuing operations	915	(658)	52	(83)	226
Net income (loss)	915[(2)]	32	52	(83)	916
Total assets	23,290	6,942	3,278	(241)	33,269
Capital expenditures	1,678	55	—	—	1,733

(1) Includes amounts from nonutility subsidiaries, as well as Edison International (parent) that are not significant as a reportable segment.

(2) Net income available for common stock

The net income (loss) reported for nonutility power generation includes earnings from discontinued operations of $98 million for 2006, $29 million for 2005 and $690 million for 2004.

Geographic Information

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

In millions	Year ended December 31,	**2006**	2005	2004
Revenue				
United States		**$12,563**	$11,789	$10,096
International		**59**	63	103
Total		**$12,622**	$11,852	$10,199

In millions	December 31,	**2006**	2005
Assets			
United States		**$33,965**	$32,481
International		**2,296**	2,299
Assets of discontinued operations		**—**	11
Total		**$36,261**	$34,791

Note 18. Discontinued Operations

On February 3, 2005, EME sold its 25% equity interest in the Tri Energy project, pursuant to a purchase agreement dated December 15, 2004, to IPM, for approximately $20 million. The sale of this investment had no significant effect on net income in the first quarter of 2005.

On January 10, 2005, EME sold its 50% equity interest in the Caliraya-Botocan-Kalayaan project to Corporacion IMPSA S.A., pursuant to a purchase agreement dated November 5, 2004. Proceeds from the sale were approximately $104 million. EME recorded a pre-tax gain on the sale of approximately $9 million during the first quarter of 2005.

On December 16, 2004, EME sold the stock and related assets of MECIBV to IPM, pursuant to a purchase agreement dated July 29, 2004. The purchase agreement was entered into following a competitive bidding process. The sale of MECIBV included the sale of EME's interests in ten electric power generating projects or companies located in Europe, Asia, Australia, and Puerto Rico. Consideration from the sale of MECIBV and related assets was $2.0 billion.

On September 30, 2004, EME sold its 51% interest in Contact Energy to Origin Energy New Zealand Limited pursuant to a purchase agreement dated July 20, 2004. The purchase agreement was entered into following a competitive bidding process. Consideration for the sale was NZ$1.6 billion (approximately $1.1 billion) which includes NZ$535 million of debt assumed by the purchaser.

"ME previously owned a 220-MW power plant located in the United Kingdom, referred to as the Lakeland project. An administrative receiver was appointed in 2002 as a result of a default by its counterparty, a subsidiary of TXU Europe Group plc. Following a claim for termination of the power sales agreement, the Lakeland project received a settlement of £116 million (approximately $217 million). EME is entitled to receive the remaining amount of the settlement after payment of creditor claims. As creditor claims have been settled, EME has received to date payments of £13 million (approximately $24 million) in 2005, £72 million (approximately $125 million) in 2006 and £4 million (approximately $8 million) in January 2007. The after-tax income attributable to the Lakeland project was $85 million and $24 million for 2006 and 2005, respectively, and none in 2004. Beginning in 2002, EME reported the Lakeland project as discontinued operations and accounts for its ownership of Lakeland Power on the cost method (earnings are recognized as cash is distributed from the project).

For all years presented, the results of EME's international projects, discussed above, have been accounted for as discontinued operations on the consolidated financial statements in accordance with SFAS No. 144.

There was no revenue from discontinued operations in 2006 or 2005. Revenue from discontinued operations was $1.3 billion in 2004. The pre-tax earnings (loss) from discontinued operations was $118 million in 2006, $(20) million in 2005 and $737 million in 2004. The pre-tax loss from discontinued operations in 2005 included a $9 million gain on sale before taxes. The pre-tax earnings from discontinued operations in 2004 included a $532 million gain on sale before taxes related to EME's international power generation portfolio.

During the fourth quarter of 2006, EME recorded a tax benefit adjustment of $22 million, which resulted from resolution of a tax uncertainty pertaining to the ownership interest in a foreign project. EME's payment of $34 million during the second quarter of 2006 related to an indemnity to IPM for matters arising out of the exercise by one of its project partners of a purported right of first refusal resulted in a $3 million additional loss recorded in 2006. During the fourth quarter of 2005, EME recorded an after-tax charge of $25 million related to a tax indemnity for a project sold to IPM in December 2004. This charge related to an adverse tax court ruling in Spain, which the local company appealed. During the third quarter of 2005, EME recorded tax benefit adjustments of $28 million, which resulted from completion of the 2004 federal and California income tax returns and quarterly review of tax accruals. Most of the tax adjustments are related to the sale of the international projects in December 2004. These adjustments (benefits) are included in income from discontinued operations—net of tax on the consolidated statements of income.

There were no assets or liabilities of discontinued operations at December 31, 2006. At December 31, 2005, the assets and liabilities of discontinued operations were segregated on the consolidated balance sheet and consisted of current assets of $2 million, other long-term assets of $9 million and long-term liabilities of $14 million.

Note 19. Acquisitions and Dispositions

Acquisitions

On January 5, 2006, EME completed a transaction with Cielo Wildorado, G.P., LLC and Cielo Capital, L.P. to acquire a 99.9% interest in the Wildorado Wind Project, which owns a 161-MW wind farm located in the panhandle of northern Texas, referred to as the Wildorado wind project. The acquisition included all development rights, title and interest held by Cielo in the Wildorado wind project, except for a small minority stake in the project retained by Cielo. The total purchase price was $29 million. As of December 31, 2006, a cash payment of $18 million had been made towards the purchase price. This project started construction in April 2006 and is scheduled for completion in April 2007, with total construction costs, excluding capitalized interest, estimated to be $270 million. The acquisition was accounted for utilizing the purchase method. The fair value of the Wildorado wind project was equal to the purchase price and as a result, the total purchase price was allocated to nonutility property in Edison International's consolidated balance sheet.

On December 27, 2005, EME completed a transaction with Padoma Project Holdings, LLC to acquire a 100% interest in the San Juan Mesa Wind Project, which owns a 120 MW wind power generation facility located in New Mexico, referred to as the San Juan Mesa wind project. The total purchase price was approximately $157 million. The acquisition was funded with cash. The acquisition was accounted for utilizing the purchase method. The fair value of the San Juan Mesa wind project was equal to the purchase price and as a result, the entire purchase price was allocated to nonutility property in Edison International's consolidated balance sheet. Edison International's consolidated statement of income reflected the operations of the San Juan Mesa project beginning January 1, 2006. The pro forma effects of the San Juan Mesa wind project acquisition on Edison International's consolidated financial statements were not material.

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

Dispositions

On March 7, 2006, EME completed the sale of a 25% ownership interest in the San Juan Mesa wind project to Citi Renewable Investments I LLC, a wholly owned subsidiary of Citicorp North America, Inc. Proceeds from the sale were $43 million. EME recorded a pre-tax gain on the sale of approximately $4 million during the first quarter of 2006.

In March 2004, EME completed the sale of its 50% partnership interest in Brooklyn Navy Yard Cogeneration Partners L.P. for a sales price of approximately $42 million. EME recorded an impairment charge of

$53 million during the fourth quarter of 2003 related to the planned disposition of this investment and a pre-tax loss of approximately $4 million during the first quarter of 2004 due to changes in the terms of the sale.

In January 2004, EME completed the sale of 100% of its stock of Edison Mission Energy Oil & Gas, which in turn held minority interests in Four Star Oil & Gas. Proceeds from the sale were approximately $100 million. EME recorded a pre-tax gain on the sale of approximately $47 million during the first quarter of 2004.

Note 20. Investments in Leveraged Leases, Partnerships and Unconsolidated Subsidiaries

Leveraged Leases

Edison Capital is the lessor in various power generation, electric transmission and distribution, transportation and telecommunication leases with terms of 24 to 38 years. Each of Edison Capital's leveraged lease transactions was completed and accounted for in accordance with SFAS No. 13, Accounting for Leases. All operating, maintenance, insurance and decommissioning costs are the responsibility of the lessees. The acquisition cost of these facilities was $6.9 billion at both December 31, 2006 and 2005. 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,	**2006**	2005	2004
Income from leveraged leases	**$ 67**	$ 71	$ 81
Tax effect of pre-tax income:			
Current	**41**	45	35
Deferred	**(66)**	(72)	(64)
Total tax expense	**(25)**	(27)	(29)
Net income from leveraged leases	**$ 42**	$ 44	$ 52

The net investment in leveraged leases is:

In millions December 31,	**2006**	2005
Rentals receivable – net	**$ 3,411**	$ 3,431
Estimated residual value	**42**	42
Unearned income	**(958)**	(1,026)
Investment in leveraged leases	**2,495**	2,447
Deferred income taxes	**(2,268)**	(2,203)
Net investment in leveraged leases	**$ 227**	$ 244

Rental receivables are net of principal and interest on nonrecourse debt, credit reserves and the current portion of rentals receivable. Credit reserves were $10 million and $16 million at December 31, 2006 and 2005, respectively. The current portion of rentals receivable was $36 million and $32 million at December 31, 2006 and 2005, respectively.

Partnerships and Unconsolidated Subsidiaries

Edison International and its nonutility subsidiaries have equity interests primarily in energy projects, oil and gas and real estate investment partnerships. On January 7, 2004, EME sold 100% of its stock of Edison Mission Energy Oil & Gas, which in turn held minority interests in Four Star Oil & Gas. On March 31, 2004, EME sold its interest in Brooklyn Navy Yard. Therefore, Four Star Oil & Gas is not included in the balances for 2006, 2005 and 2004. Brooklyn Navy Yard's first quarter 2004 results are included in the summarized financial information for 2004. In compliance with FIN 46, on March 31, 2004, SCE began consolidating four power projects (Kern River, Midway-Sunset, Sycamore and Watson) partially owned by EME; therefore, they are not included in the balances for 2004. See Note 14 for further details.

The difference between the carrying value of these equity investments and the underlying equity in the net assets was $14 million at December 31, 2006. The difference is being amortized over the life of the energy projects.

Summarized financial information of these investments is:

In millions	Year ended December 31,	**2006**	2005	2004
Revenue		**$707**	$717	$719
Expenses		**676**	745	698
Net income (loss)		**$ 31**	$ (28)	$ 21

In millions	December 31,	**2006**	2005
Current assets		**$ 372**	$ 446
Other assets		**3,864**	4,376
Total assets		**$4,236**	$4,822
Current liabilities		**$ 247**	$ 333
Other liabilities		**2,170**	2,353
Equity		**1,819**	2,136
Total liabilities and equity		**$4,236**	$4,822

The undistributed earnings of equity method investments were $8 million in 2006 and $21 million in 2005.

Impairment Loss on Equity Method Investment

During the third quarter of 2005, EME fully impaired its equity investment in the March Point project following an updated forecast of future project cash flows. The March Point project is a 140 MW natural gas-fired cogeneration facility located in Anacortes, Washington, in which a subsidiary of EME owns a 50% partnership interest. The March Point project sells electricity to Puget Sound Energy, Inc. under two power purchase agreements that expire in 2011 and sells steam to Equilon Enterprises, LLC (a subsidiary of Shell Oil) under a steam supply agreement that also expires in 2011. March Point purchases a portion of its fuel requirements under long-term contracts with the remaining requirements purchased at current market prices. March Point's power sales agreements do not provide for a price adjustment related to the project's fuel costs. During the first nine months of 2005, long-term natural gas prices increased substantially, thereby adversely affecting the future cash flows of the March Point project. As a result, EME concluded that its investment was impaired and recorded a $55 million charge during the third quarter of 2005.

Note 21. Asset Impairment and Loss on Lease Termination

Asset Impairment

In September 2004, EME completed an analysis of future competitiveness in the expanded PJM marketplace of its eight remaining small peaking units in Illinois. Based on this analysis, EME decided to decommission six of the eight small peaking units. As a result of the decision to decommission the units, projected cash flows associated with the Illinois peaking units were less than the book value of the units resulting in an impairment under SFAS No. 144. During the third quarter of 2004, EME recorded a pre-tax impairment charge of $29 million (approximately $18 million after tax).

Loss on Lease Termination

In April 2004, Midwest Generation terminated the Collins Station lease through a negotiated transaction with the lease equity investor. Midwest Generation made a lease termination payment of approximately $960 million. This amount represented the $774 million of lease debt outstanding, plus accrued interest, and the amount owed to the lease equity investor for early termination of the lease. Midwest Generation received title to the Collins Station as part of the transaction. EME recorded a pre-tax loss of approximately $956 million (approximately $587 million after tax) due to termination of the lease, and the planned decommissioning of the asset and disposition of excess inventory.

Note 22. Quarterly Financial Data (Unaudited)

	2006				
In millions, except per-share amounts	Total	Fourth	Third	Second	First
Operating revenue	$12,622	$3,067	$3,802	$3,001	$2,751
Operating income	2,490	474	963	591	462
Income from continuing operations	1,083	266	460	173	184
Income (loss) from discontinued operations – net	97	22	(2)	4	73
Cumulative effect of accounting change – net	1	—	—	—	1
Net income	1,181	288	458	177	258
Basic earnings (loss) per share:					
Continuing operations	3.28	0.80	1.39	0.53	0.56
Discontinued operations	0.30	0.07	(0.01)	0.01	0.22
Total	3.58	0.87	1.38	0.54	0.78
Diluted earnings (loss) per share:					
Continuing operations	3.28	0.80	1.39	0.53	0.56
Discontinued operations	0.29	0.07	(0.01)	0.01	0.22
Total	3.57	0.87	1.38	0.54	0.78
Dividends declared per share	1.10	0.29	0.27	0.27	0.27
Common stock prices:					
High	47.15	47.15	43.79	42.23	46.60
Low	37.90	41.69	38.06	37.90	40.86
Close	45.48	45.48	41.64	39.00	41.18

	2005				
In millions, except per-share amounts	Total	Fourth	Third	Second	First
Operating revenue	$11,852	$2,975	$3,783	$2,649	$2,446
Operating income	2,313	612	843	409	448
Income from continuing operations	1,108	299	435	180	194
Income (loss) from discontinued operations – net	30	(26)	27	21	7
Cumulative effect of accounting change – net	(1)	(1)	—	—	—
Net income	1,137	272	462	201	201
Basic earnings (loss) per share:					
Continuing operations	3.38	0.91	1.33	0.55	0.59
Discontinued operations	0.09	(0.08)	0.08	0.06	0.02
Total	3.47	0.83	1.41	0.61	0.61
Diluted earnings (loss) per share:					
Continuing operations	3.34	0.90	1.31	0.55	0.59
Discontinued operations	0.09	(0.08)	0.08	0.06	0.02
Total	3.43	0.82	1.39	0.61	0.61
Dividends declared per share	1.02	0.27	0.25	0.25	0.25
Common stock prices:					
High	49.16	49.16	47.64	40.96	34.95
Low	30.43	40.51	38.75	34.70	30.43
Close	43.61	43.61	47.28	40.55	34.72

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

Selected Financial Data: 2002 – 2006

Edison International

Dollars in millions, except per-share amounts	**2006**	2005	2004	2003	2002
Edison International and Subsidiaries					
Operating revenue	**$12,622**	$11,852	$10,199	$10,732	$10,451
Operating expenses	**$10,132**	$ 9,539	$ 9,099	$ 9,277	$ 8,235
Income from continuing operations	**$ 1,083**	$ 1,108	$ 226	$ 655	$ 1,055
Net income	**$ 1,181**	$ 1,137	$ 916	$ 821	$ 1,077
Weighted-average shares of common stock outstanding (in millions)	**326**	326	326	326	326
Basic earnings (loss) per share:					
Continuing operations	**$ 3.28**	$ 3.38	$ 0.69	$ 2.01	$ 3.24
Discontinued operations	**$ 0.30**	$ 0.09	$ 2.12	$ 0.54	$ 0.07
Cumulative effect of accounting change	**$ —**	$ —	$ —	$ (0.03)	$ —
Total	**$ 3.58**	$ 3.47	$ 2.81	$ 2.52	$ 3.31
Diluted earnings per share	**$ 3.57**	$ 3.43	$ 2.77	$ 2.50	$ 3.28
Dividends declared per share	**$ 1.10**	$ 1.02	$ 0.85	$ 0.20	$ —
Book value per share at year-end	**$ 23.66**	$ 20.30	$ 18.56	$ 16.52	$ 13.62
Market value per share at year-end	**$ 45.48**	$ 43.61	$ 32.03	$ 21.93	$ 11.85
Rate of return on common equity	**16.5%**	18.1%	17.1%	17.1%	27.0%
Price/earnings ratio	**12.7**	12.6	11.4	8.7	3.6
Ratio of earnings to fixed charges	**2.48**	2.49	1.11	1.58	1.92
Total assets	**$36,261**	$34,791	$33,269	$38,267	$51,028
Long-term debt	**$ 9,101**	$ 8,833	$ 9,678	$ 9,220	$ 9,728
Common shareholders' equity	**$ 7,709**	$ 6,615	$ 6,049	$ 5,383	$ 4,437
Preferred stock subject to mandatory redemption	**$ —**	$ —	$ 139	$ 141	$ 147
Company-obligated mandatorily redeemable securities of subsidiaries holding solely parent company debentures	**$ —**	$ —	$ —	$ —	$ 951
Retained earnings	**$ 5,551**	$ 4,798	$ 4,078	$ 3,466	$ 2,711
Southern California Edison Company					
Operating revenue	**$10,312**	$ 9,500	$ 8,448	$ 8,854	$ 8,706
Net income available for common stock	**$ 776**	$ 725	$ 915	$ 922	$ 1,228
Basic earnings per Edison International common share	**$ 2.38**	$ 2.22	$ 2.81	$ 2.83	$ 3.77
Total assets	**$26,110**	$24,703	$23,290	$21,771	$36,058
Rate of return on common equity	**15.0%**	15.3%	21.0%	20.2%	31.8%
Mission Energy Holding Company					
Revenue	**$ 2,239**	$ 2,265	$ 1,653	$ 1,779	$ 1,713
Income (loss) from continuing operations	**$ 246**	$ 332	$ 658	$ (195)	$ (73)
Net income (loss)	**$ 344**	$ 360	$ 32	$ (80)	$ (65)
Total assets	**$ 7,283**	$ 7,074	$ 7,147	$12,480	$11,495
Rate of return on common equity	**23.3%**	36.8%	4.2%	(10.1)%	(8.0)%
Edison Capital					
Revenue	**$ 73**	$ 77	$ 87	$ 86	$ 7
Net income	**$ 89**	$ 81	$ 52	$ 58	$ 30
Total assets	**$ 3,199**	$ 3,376	$ 3,279	$ 3,196	$ 3,351
Rate of return on common equity	**9.6%**	12.3%	8.1%	7.9%	4.3%

The selected financial data was derived from Edison International's audited financial statements and is qualified in its entirety by the more detailed information and financial statements, including notes to these financial statements, included in this annual report. Amounts presented in this table have been restated to reflect Edison Capital's capital contribution to MEHC. See "Basis of Presentation" in Note 1 for further discussion. During 2004, EME sold 11 international projects. During 2003, SCE sold certain oil storage and pipeline facilities. During 2002, EME recorded an impairment charge related to its Lakeland plant. Amounts presented in this table have been restated to reflect continuing operations unless stated otherwise. See Note 18, *Discontinued Operations, for further discussion.*

Board of Directors*

John E. Bryson [3]
Chairman of the Board,
President and
Chief Executive Officer,
Edison International;
Chairman of the Board,
Southern California Edison Company
A director since 1990†

France A. Córdova [4,5]
Chancellor,
University of California, Riverside
Riverside, California
A director since 2004

Charles B. Curtis [4,5]
President and Chief Operating Officer,
Nuclear Threat Initiative
(private foundation dealing with
national security issues)
Washington, DC
A director since 2006

Bradford M. Freeman [1,2,5]
Founding Partner,
Freeman Spogli & Co.
(private investment company)
Los Angeles, California
A director since 2002

Luis G. Nogales [1,2,4]
Managing Partner,
Nogales Investors, LLC
(private equity investment company)
Los Angeles, California
A director since 1993

Ronald L. Olson [3,4]
Senior Partner,
Munger, Tolles and Olson (law firm)
Los Angeles, California
A director since 1995

James M. Rosser [3,4]
President,
California State University, Los Angeles
Los Angeles, California
A director since 1988

Richard T. Schlosberg, III [1,2,5]
Retired President and
Chief Executive Officer,
The David and Lucile Packard Foundation
(private family foundation)
San Antonio, Texas
A director since 2002

Robert H. Smith [1,2,5]
Robert H. Smith Investments and Consulting
(banking and financial-
related consulting services)
Pasadena, California
A director since 1988

Thomas C. Sutton [1,2,3]
Chairman of the Board and
Chief Executive Officer,
Pacific Life Insurance Company
Newport Beach, California
A director since 1995

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

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

† For Southern California Edison Company, a director from 1990-1999; 2003 to present.

Edison International Management Team

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

J.A. (Lon) Bouknight
Executive Vice President
and General Counsel

Thomas R. McDaniel
Executive Vice President,
Chief Financial Officer and
Treasurer

Polly L. Gault
Executive Vice President,
Public Affairs

Cecil R. House
Senior Vice President,
Safety and Operations Support

Barbara J. Parsky
Senior Vice President,
Corporate Communications

Mahvash Yazdi
Senior Vice President,
Business Integration, and
Chief Information Officer

Jeffrey L. Barnett
Vice President,
Tax

Diane L. Featherstone
Vice President and General Auditor

Barbara E. Mathews
Vice President, Associate General Counsel,
Chief Governance Officer and Corporate
Secretary

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

Linda G. Sullivan
Vice President and
Controller

Southern California Edison Company

John E. Bryson
Chairman of the Board

Alan J. Fohrer
Chief Executive Officer

John R. Fielder
President

Polly L. Gault
Executive Vice President,
Public Affairs

Bruce C. Foster
Senior Vice President,
Regulatory Operations

Cecil R. House
Senior Vice President,
Safety and Operations Support

Ronald L. Litzinger
Senior Vice President,
Transmission and Distribution

Thomas M. Noonan
Senior Vice President and
Chief Financial Officer

Barbara J. Parsky
Senior Vice President,
Corporate Communications

Stephen E. Pickett
Senior Vice President and
General Counsel

Pedro J. Pizarro
Senior Vice President,
Power Procurement

Richard M. Rosenblum
Senior Vice President,
Generation and Chief Nuclear Officer

Mahvash Yazdi
Senior Vice President,
Business Integration, and
Chief Information Officer

Lynda L. Ziegler
Senior Vice President,
Customer Service

Jeffrey L. Barnett
Vice President,
Tax

Robert C. Boada
Vice President and Treasurer

William L. Bryan
Vice President,
Business Customer Division

Kevin R. Cini
Vice President,
Energy Supply and Management

Ann P. Cohn
Vice President and
Associate General Counsel

Jodi M. Collins
Vice President,
Information Technology

Diane L. Featherstone
Vice President and General Auditor

Harry B. Hutchison
Vice President,
Customer Service Operations

Akbar Jazayeri
Vice President,
Revenue and Tariffs

Walter J. Johnston
Vice President,
Power Delivery

Brian Katz
Vice President,
Nuclear Oversight and
Regulatory Affairs

James A. Kelly
Vice President,
Engineering and Technical Services

R. W. (Russ) Krieger, Jr.
Vice President,
Power Production

Barbara E. Mathews
Vice President,
Associate General Counsel,
Chief Governance Officer, and Corporate
Secretary

Kevin M. Payne
Vice President,
Enterprise Resource Planning

Frank J. Quevedo
Vice President,
Equal Opportunity

James T. Reilly
Vice President,
Nuclear Engineering and
Technical Services

Tommy Ross
Vice President,
Public Affairs

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

Linda G. Sullivan
Vice President and
Controller

Raymond W. Waldo
Vice President,
Nuclear Generation

Edison Mission Group*

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

Guy F. Gorney
Senior Vice President,
Coal Generation

Paul Jacob
Senior Vice President,
Marketing and Trading

W. James Scilacci
Senior Vice President and
Chief Financial Officer

Raymond W. Vickers
Senior Vice President and
General Counsel

John P. Finneran, Jr.
Senior Vice President,
Business Management

Gerard P. Loughman
Senior Vice President,
Development

Jenene J. Wilson
Vice President,
Human Resources

* Parent company of Edison Mission Energy and Edison Capital.

Edison International Annual Report Shareholder Information

Annual Meeting

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

Corporate Governance Practices

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

Stock Listing and Trading Information

Edison International Common Stock
The New York Stock Exchange uses the ticker symbol EIX; daily newspapers list the stock as EdisonInt.

Transfer Agent and Registrar

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

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

Inquiries may also be directed to:

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

Fax
(651) 450-4033

Wells Fargo Shareowner Services[SM]
www.wellsfargo.com/shareownerservices

Web Address
www.edisoninvestor.com

Online account information
www.shareowneronline.com

Dividend Reinvestment and Direct Stock Purchase Plan

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

This annual report is printed on recycled paper.

EDISON
INTERNATIONAL

2244 WALNUT GROVE AVENUE
ROSEMEAD, CALIFORNIA 91770
www.edison.com

SOUTHERN CALIFORNIA
EDISON®

An *EDISON INTERNATIONAL*® Company

2006 Annual Report

Southern California Edison Company

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

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

Table of Contents

Glossary

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

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

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

INTRODUCTION

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

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

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

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

MANAGEMENT OVERVIEW

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

- Implementation of SCE's capital investment plan to meet system growth and ensure reliability – During 2006, the CPUC authorized, through the 2006 GRC proceeding, a net increase of $134 million in SCE's 2006 base rate revenue and supported SCE's capital investment plan to ensure system reliability. In 2006, SCE undertook new projects to expand its generation, transmission and distribution systems, including pursuing the permitting and construction of five combustion turbine peaker plants, each with a capacity of approximately 45 MW and made continued progress in permitting the expansion of SCE's transmission system, which will result in the interconnection of renewable generation as well as increased transfer capacity. See "Regulatory Matters—Current Regulatory Developments—2006 General Rate Case Proceeding" and "—Peaker Plant Generation Projects" for further discussion of these matters.
- Progress toward a set of market rules that permit SCE to procure power efficiently – SCE made significant progress in 2006 to ensure that its customers have adequate energy resources available to meet their needs. SCE received CPUC approval of rules to enter into 10-year contracts for new generation projects serving its service territory, with all benefits and costs allocated across all its distribution service customers, including customers of community choice aggregators and direct access providers. SCE added significant new renewable energy contracts, including the nation's largest wind contract, and is currently in negotiations with counterparties resulting from a request for offers from renewable resources. SCE's energy portfolio currently meets all required year-ahead system and local resource adequacy requirements. SCE has also been working with a broad range of market participants on a capacity market design that would support development of sufficient resources while allocating cost responsibility fairly across all customers.

Other significant developments in 2006:

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

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

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

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

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

LIQUIDITY

Overview

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

SCE's 2007 estimated cash outflows consist of:

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

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

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

Capital Expenditures

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

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

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

Credit Ratings

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

Dividend Restrictions and Debt Covenants

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

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

Margin and Collateral Deposits

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

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

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

Rate Reduction Notes

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

REGULATORY MATTERS

Overview of Ratemaking Mechanisms

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

Base Rates

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

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

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

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

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

Cost-Recovery Rates

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

CDWR-Related Rates

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

Impact of Regulatory Matters on Customer Rates

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

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

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

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

Current Regulatory Developments

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

2006 General Rate Case Proceeding

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

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

2006 Cost of Capital Proceeding

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

2007 Cost of Capital Proceeding

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

2006 FERC Rate Case

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

Energy Resource Recovery Account Proceedings

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

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

Resource Adequacy Requirements

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

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

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

Peaker Plant Generation Projects

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

Procurement of Renewable Resources

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

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

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

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

Request for Offers from Renewable Resources

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

Mohave Generating Station and Related Proceedings

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

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

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

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

San Onofre Nuclear Generating Station Steam Generators and Changes in Ownership

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

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

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

Palo Verde Nuclear Generating Station Steam Generators

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

ISO Disputed Charges

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

Scheduling Coordinator Tariff Dispute

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

FERC Refund Proceedings

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

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

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

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

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

Holding Company Order Instituting Rulemaking

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

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

Investigations Regarding Performance Incentives Rewards

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

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

Customer Satisfaction

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

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

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

Employee Injury and Illness Reporting

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

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

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

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

System Reliability

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

CPUC Investigation

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

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

Settlement Agreement with Duke Energy Trading and Marketing, LLC

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

OTHER DEVELOPMENTS

Environmental Matters

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

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

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

Air Quality Standards

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

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

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

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

Climate Change

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

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

Environmental Remediation

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

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

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

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

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

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

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

Enterprise-Wide Software System Project

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

Federal and State Income Taxes

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

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

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

Midway-Sunset Cogeneration Company

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

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

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

Navajo Nation Litigation

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

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

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

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

Nuclear Insurance

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

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

Palo Verde Nuclear Generating Station Outage and Inspection

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

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

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

Spent Nuclear Fuel

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

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

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

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

MARKET RISK EXPOSURES

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

Interest Rate Risk

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

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

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

Commodity Price Risk

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

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

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

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

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

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

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

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

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

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

Credit Risk

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

RESULTS OF OPERATIONS AND HISTORICAL CASH FLOW ANALYSIS

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

Results of Operations

Net Income Available for Common Stock

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

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

Operating Revenue

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

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

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

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

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

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

Operating Expenses

Fuel Expense

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

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

Purchased-Power Expense

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

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

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

Provisions for Regulatory Adjustment Clauses – Net

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

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

Other Operation and Maintenance Expense

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

Depreciation, Decommissioning and Amortization Expense

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

Other Income and Deductions

Interest Income

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

Other Nonoperating Income

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

Interest Expense – Net of Amounts Capitalized

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

Income Tax Expense

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

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

Historical Cash Flow Analysis

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

Cash Flows from Operating Activities

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

Cash Flows from Financing Activities

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

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

- In January 2006, SCE issued $500 million of first and refunding mortgage bonds which consisted of $350 million of 5.625% bonds due in 2036 and $150 million of floating rate bonds due in 2009. The proceeds from this issuance were used to redeem $150 million of variable rate first and refunding mortgage bonds due in January 2006 and $200 million of its 6.375% first and refunding mortgage bonds due in January 2006.
- In January 2006, SCE issued two million shares of 6% Series C preference stock (noncumulative, $100 liquidation value) and received net proceeds of $197 million.
- In April 2006, SCE issued $331 million of pollution control bonds which consisted of $196 million of 4.10% bonds due in 2028 and $135 million of 4.25% bonds due in 2033. The proceeds from this issuance were used to redeem a total of $331 million of pollution control bonds due in 2008. This transaction was treated as a noncash financing activity.
- In December 2006, SCE issued $400 million of 5.55% first and refunding mortgage bonds due in 2037. The proceeds from this issuance were used for general corporate purposes.
- Financing activities in 2006 also included dividend payments of $300 million paid to Edison International.

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

- In January 2005, SCE issued $650 million of first and refunding mortgage bonds which consisted of $400 million of 5% bonds due in 2016 and $250 million of 5.55% bonds due in 2036. The proceeds from this issuance were used to redeem the remaining $50,000 of its 8% first and refunding mortgage bonds due February 2007 (Series 2003A) and $650 million of the $966 million 8% first and refunding mortgage bonds due February 2007 (Series 2003B).
- In March 2005, SCE issued $203 million of 3.55% pollution control bonds due in 2029. The proceeds from this issuance were used to redeem $49 million of 7.20% pollution control bonds due in 2021 and $155 million of 5.875% pollution control bonds due in 2023. This transaction was treated as a noncash financing activity.
- In April 2005, SCE issued 4,000,000 shares of Series A preference stock (noncumulative, 100% liquidation value) and received net proceeds of approximately $394 million. Approximately $81 million of the proceeds was used to redeem all the outstanding shares of its $100 cumulative preferred stock, 7.23% Series, and approximately $64 million of the proceeds was used to redeem all the outstanding shares of its $100 cumulative preferred stock, 6.05% Series.

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

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

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

Cash Flows from Investing Activities

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

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

ACQUISITIONS

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

CRITICAL ACCOUNTING ESTIMATES

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

Rate Regulated Enterprises

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

Derivative Financial Instruments and Hedging Activities

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

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

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

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

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

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

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

Income Taxes

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

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

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

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

Asset Impairment

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

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

Nuclear Decommissioning

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

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

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

Pensions and Postretirement Benefits Other than Pensions

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

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

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

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

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

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

NEW ACCOUNTING PRONOUNCEMENTS

Accounting Pronouncements Adopted

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

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

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

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

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

Accounting Pronouncements Not Yet Adopted

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

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

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

COMMITMENTS AND INDEMNITIES

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

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

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

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

Fuel Supply Contracts

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

Power-Purchase Contracts

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

Operating and Capital Leases

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

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

Other Commitments

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

Indemnities

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

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

Report of Independent Registered Public Accounting Firm

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

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

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

PricewaterhouseCoopers LLP

Los Angeles, California
February 28, 2007

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

Consolidated Statements of Comprehensive Income

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

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

Consolidated Balance Sheets

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

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

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

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

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

Consolidated Statements of Cash Flows

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

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

Consolidated Statements of Changes in Common Shareholders' Equity

Southern California Edison Company

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

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

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

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

Note 1. Summary of Significant Accounting Policies

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

Basis of Presentation

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

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

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

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

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

Book Overdrafts

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

Cash and Equivalents

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

Deferred Financing Costs

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

Derivative Instruments and Hedging Activities

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

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

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

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

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

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

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

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

Dividend Restriction

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

Impairment of Long-Lived Assets

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

Income Taxes

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

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

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

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

Inventory

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

Leases

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

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

Margin and Collateral Deposits

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

New Accounting Pronouncements

Accounting Pronouncements Adopted

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

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

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

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

Accounting Pronouncements Not Yet Adopted

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

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

Nuclear Decommissioning

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

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

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

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

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

Planned Major Maintenance

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

Property and Plant

Utility Plant

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

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

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

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

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

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

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

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

Nonutility Property

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

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

Estimated useful lives for nonutility property are as follows:

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

Purchased Power

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

Receivables

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

Regulatory Assets and Liabilities

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

Related Party Transactions

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

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

Restricted Cash

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

Revenue Recognition

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

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

Stock-Based Compensation

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

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

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

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

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

Note 2. Derivative Instruments and Hedging Activities

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

Note 3. Liabilities and Lines of Credit

Long-Term Debt

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

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

Long-term debt is:

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

Note: Rates and terms as of December 31, 2006

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

Short-Term Debt

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

Lines of Credit

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

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

Preferred Stock Subject to Mandatory Redemption

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

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

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

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

Note 4. Income Taxes

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

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

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

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

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

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

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

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

Note 5. Compensation and Benefit Plans

Employee Savings Plan

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

Pension Plans and Postretirement Benefits Other Than Pensions

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

Pension Plans

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

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

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

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

Information on plan assets and benefit obligations is shown below:

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

Expense components are:

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

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

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

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

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

Asset allocations are:

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

Postretirement Benefits Other Than Pensions

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

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

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

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

Information on plan assets and benefit obligations is shown below:

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

Expense components are:

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

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

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

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

The following benefit payments are expected to be paid:

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

Asset allocations are:

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

Description of Pension and Postretirement Benefits Other Than Pensions Investment Strategies

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

Allowable investment types include:

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

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

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

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

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

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

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

Capital Markets Return Forecasts

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

Stock-Based Compensation

Stock Options

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

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

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

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

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

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

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

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

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

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

Performance Shares

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

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

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

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

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

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

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

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

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

Note 6. Commitments and Contingencies

Lease Commitments

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

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

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

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

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

Nuclear Decommissioning Commitment

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

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

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

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

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

Trust investments (at fair value) include:

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

Note: Maturity dates as of December 31, 2006.

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

Other Commitments

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

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

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

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

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

Indemnities

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

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

Contingencies

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

2006 GRC Proceeding

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

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

Environmental Remediation

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

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

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

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

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

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

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

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

Federal and State Income Taxes

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

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

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

FERC Refund Proceedings

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

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

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

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

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

Investigations Regarding Performance Incentives Rewards

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

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

Customer Satisfaction

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

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

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

Employee Injury and Illness Reporting

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

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

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

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

CPUC Investigation

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

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

ISO Disputed Charges

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

Midway-Sunset Cogeneration Company

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

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

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

Navajo Nation Litigation

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

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

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

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

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

Nuclear Insurance

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

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

Procurement of Renewable Resources

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

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

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

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

Scheduling Coordinator Tariff Dispute

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

Settlement Agreement with Duke Energy Trading and Marketing, LLC

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

Spent Nuclear Fuel

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

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

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

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

Note 7. Accumulated Other Comprehensive Loss Information

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

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

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

Note 8. Property and Plant

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

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

Asset Retirement Obligations

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

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

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

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

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

Note 9. Supplemental Cash Flows Information

SCE supplemental cash flows information is:

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

Note 10. Fair Values of Financial Instruments

The carrying amounts and fair values of financial instruments are:

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

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

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

Note 11. Regulatory Assets and Liabilities

Included in SCE's regulatory assets and liabilities are regulatory balancing accounts. Sales balancing accounts accumulate differences between recorded revenue and revenue SCE is authorized to collect through rates. Cost balancing accounts accumulate differences between recorded costs and costs SCE is authorized to recover through rates. Undercollections are recorded as regulatory balancing account assets. Overcollections are recorded as regulatory balancing account liabilities. SCE's regulatory balancing accounts accumulate balances until they are refunded to or received from SCE's customers through authorized rate adjustments. Primarily all of SCE's balancing accounts can be classified as one of the following types: generation-revenue related, distribution-revenue related, generation-cost related, distribution-cost related, transmission-cost related or public purpose and other cost related.

Balancing account undercollections and overcollections accrue interest based on a three-month commercial paper rate published by the Federal Reserve. Income tax effects on all balancing account changes are deferred.

Amounts included in regulatory assets and liabilities are generally recorded with corresponding offsets to the applicable income statement accounts, except for regulatory balancing accounts, which are offset through the "Provisions for regulatory adjustments clauses – net" account.

Regulatory Assets

Regulatory assets included on the consolidated balance sheets are:

In millions December 31,	**2006**	2005
Current:		
Regulatory balancing accounts	**$ 128**	$ 355
Rate reduction notes – transition cost deferral	**219**	—
Direct access procurement charges	**63**	113
Energy derivatives	**88**	—
Purchased-power settlements	**31**	53
Other	**25**	15
	554	536
Long-term:		
Flow-through taxes – net	**1,023**	1,066
Rate reduction notes – transition cost deferral	**—**	465
Unamortized nuclear investment – net	**435**	487
Nuclear-related ARO investment – net	**317**	292
Unamortized coal plant investment – net	**102**	97
Unamortized loss on reacquired debt	**318**	323
Direct access procurement charges	**—**	40
SFAS No. 158 pensions and other postretirement benefits	**303**	—
Energy derivatives	**145**	58
Environmental remediation	**77**	56
Purchased-power settlements	**8**	39
Other	**90**	90
	2,818	3,013
Total Regulatory Assets	**$ 3,372**	$ 3,549

SCE's regulatory asset related to the rate reduction bonds is amortized simultaneously with the amortization of the rate reduction bonds liability, and is expected to be recovered by the end of 2007. SCE's regulatory assets related to direct access procurement charges are for amounts direct access customers owe bundled service customers for the period May 1, 2000 through August 31, 2001, and are offset by corresponding regulatory liabilities to the bundled service customers. These amounts will be collected by late 2007. SCE's regulatory assets related to energy derivatives are an offset to unrealized losses on recorded derivatives and an offset to lease accruals. SCE's regulatory assets related to purchased-power settlements will be recovered through 2008. Based on current regulatory ratemaking and income tax laws, SCE expects to recover its net regulatory assets related to flow-through taxes over the life of the assets that give rise to the accumulated deferred income taxes. SCE's nuclear-related regulatory assets are expected to be recovered by the end of the remaining useful lives of the nuclear facilities. SCE's net regulatory asset related to its unamortized coal plant investment is being recovered through June 2016. SCE's net regulatory asset related to its unamortized loss on reacquired debt will be recovered over the remaining original amortization period of the reacquired debt over periods ranging from one year to 28 years. SCE's regulatory asset related to SFAS No. 158 represents the offset to the additional amounts recorded in accordance with SFAS No. 158 (see "Pension Plans and Postretirement Benefits Other Than Pensions" discussion in Note 5). This amount will be recovered through rates charged to customers. SCE's regulatory asset related to environmental remediation represents the portion of SCE's environmental liability recognized at the end of the period in excess of the amount that has been recovered through rates charged to customers. This amount will be recovered in future rates as expenditures are made.

SCE earns a return on three of the regulatory assets listed above: unamortized nuclear investment – net, unamortized coal plant investment – net and unamortized loss on reacquired debt.

Regulatory Liabilities

Regulatory liabilities included on the consolidated balance sheets are:

In millions December 31,	**2006**	2005
Current:		
Regulatory balancing accounts	**$ 912**	$ 370
Direct access procurement charges	**63**	113
Energy derivatives	**7**	136
Other	**18**	62
	1,000	681
Long-term:		
ARO	**732**	584
Costs of removal	**2,158**	2,110
SFAS No. 158 pensions and other postretirement benefits	**145**	—
Direct access procurement charges	**—**	39
Energy derivatives	**27**	—
Employee benefit plans	**78**	229
	3,140	2,962
Total Regulatory Liabilities	**$ 4,140**	$ 3,643

SCE's regulatory liabilities related to direct access procurement charges are a liability to its bundled service customers and are offset by regulatory assets from direct access customers. SCE's regulatory liabilities related to energy derivatives are an offset to unrealized gains on recorded derivatives and an offset to a lease prepayment. SCE's regulatory liability related to the ARO represents timing differences between the recognition of AROs in accordance with generally accepted accounting principles and the amounts recognized for rate-making purposes. SCE's regulatory liabilities related to costs of removal represent revenue collected for asset removal costs that SCE expects to incur in the future. SCE's regulatory liability related to SFAS No. 158 represents the offset to the additional amounts recorded in accordance with SFAS No. 158 (see "Pension Plans and Postretirement Benefits Other Than Pensions" discussion in Note 5). This amount will be returned to ratepayers in some future rate-making proceeding. SCE's regulatory liabilities related to employee benefit plan expenses represent pension costs recovered through rates charged to customers in excess of the amounts recognized as expense or the difference between these costs calculated in accordance with rate-making methods and these costs calculated in accordance with SFAS No. 87, Employers' Accounting for

Pensions, and PBOP costs recovered through rates charged to customers in excess of the amounts recognized as expense. These balances will be returned to ratepayers in some future rate-making proceeding, be charged against expense to the extent that future expenses exceed amounts recoverable through the rate-making process, or be applied as otherwise directed by the CPUC.

Note 12. Other Nonoperating Income and Deductions

Other nonoperating income and deductions are as follows:

In millions Year ended December 31,	**2006**	2005	2004
AFUDC	**$ 32**	$ 25	$ 35
Performance-based incentive awards	**19**	33	31
Demand-side management and energy efficiency performance incentives	**—**	45	—
Other	**34**	24	18
Total other nonoperating income	**$ 85**	$ 127	$ 84
Various penalties	**$ 23**	$ 27	$ 35
Other	**37**	38	34
Total other nonoperating deductions	**$ 60**	$ 65	$ 69

Note 13. Jointly Owned Utility Projects

SCE owns interests in several generating stations and transmission systems for which each participant provides its own financing. SCE's proportionate share of expenses for each project is included in the consolidated statements of income.

SCE's investment in each project as of December 31, 2006 is:

In millions	Investment in Facility	Accumulated Depreciation and Amortization	Ownership Interest
Transmission systems:			
Eldorado	$ 72	$ 11	60%
Pacific Intertie	308	92	50
Generating stations:			
Four Corners Units 4 and 5 (coal)	506	421	48
Mohave (coal)	352	279	56
Palo Verde (nuclear)	1,746	1,477	16
San Onofre (nuclear)	4,612	3,971	78
Total	$ 7,596	$ 6,251	

All of Mohave Generating Station and a portion of San Onofre and Palo Verde is included in regulatory assets on the consolidated balance sheets – see Note 11. Mohave ceased operations on December 31, 2005. For further information on Mohave see Note 16. In December 2006, SCE acquired the City of Anaheim's approximately 3% ownership interest of San Onofre Units 2 and 3.

Note 14. Variable Interest Entities

SCE has variable interests in contracts with certain QFs that contain variable contract pricing provisions based on the price of natural gas. Four of these contracts are with entities that are partnerships owned in part by a related party, EME. These four contracts had 20-year terms at inception. The QFs sell electricity to SCE and steam to nonrelated parties. Under a new accounting standard, SCE consolidated these four projects effective March 31, 2004. Prior periods have not been restated.

Project	Capacity	Termination Date	EME Ownership
Kern River	295 MW	June 2011	50%
Midway-Sunset	225 MW	May 2009	50%
Sycamore	300 MW	December 2007	50%
Watson	385 MW	December 2007	49%

SCE has no investment in, nor obligation to provide support to, these entities other than its requirement to make contract payments. Any profit or loss generated by these entities will not effect SCE's income statement, except that SCE would be required to recognize losses if these projects have negative equity in the future. These losses, if any, would not affect SCE's liquidity. Any liabilities of these projects are nonrecourse to SCE.

Effective April 1, 2004, the VIEs' operating costs are shown in SCE's consolidated statements of income. Prior to that date, purchases under these QF contracts were reported as purchased-power expense. Further, SCE's operating revenue beginning April 1, 2004, includes revenue from the sale of steam by these four projects. The effect that these VIEs have on SCE's consolidated financial statements is shown in Note 10.

SCE also has eight other contracts with QFs that contain variable pricing provisions based on the price of natural gas and are potential VIEs. SCE might be considered to be the consolidating entity under the new accounting standard. However, these entities are not legally obligated to provide the financial information to SCE that is necessary to determine whether SCE must consolidate these entities. These eight entities have declined to provide SCE with the necessary financial information. SCE is continuing to attempt to obtain information for these projects in order to determine whether they should be consolidated by SCE. The aggregate capacity dedicated to SCE for these projects is 267 MW. SCE paid $180 million in 2006 , $198 million in 2005 and $166 million in 2004 to these projects. These amounts are recoverable in utility customer rates. SCE has no exposure to loss as a result of its involvement with these projects.

Note 15. Preferred and Preference Stock Not Subject to Mandatory Redemption

SCE's authorized shares are: $100 cumulative preferred – 12 million shares, $25 cumulative preferred – 24 million shares and preference – 50 million shares. There are no dividends in arrears for the preferred stock or preference shares. Shares of SCE's preferred stock have liquidation and dividend preferences over shares of SCE's common stock and preference stock. All cumulative preferred stock is redeemable. When preferred shares are redeemed, the premiums paid, if any, are charged to common equity. No preferred stock not subject to mandatory redemption was issued or redeemed in the last three years. There is no sinking fund redemption or repurchase of the preferred stock.

Shares of SCE's preference stock rank junior to all of the preferred stock and senior to all common stock. Shares of SCE's preference stock are not convertible into shares of any other class or series of SCE's capital stock or any other security. The preference shares are noncumulative and have a $100 liquidation value. There is no sinking fund for the redemption or repurchase of the preference shares.

Preferred stock and preference stock not subject to mandatory redemption is:

Dollars in millions, except per-share amounts	December 31, 2006 Shares Outstanding	December 31, 2006 Redemption Price	2006	2005
Cumulative preferred stock:				
$25 par value:				
4.08% Series	1,000,000	$ 25.50	$ 25	$ 25
4.24	1,200,000	25.80	30	30
4.32	1,653,429	28.75	41	41
4.78	1,296,769	25.80	33	33
Preference stock:				
No par value:				
5.349% Series A	4,000,000	100.00	400	400
6.125% Series B	2,000,000	100.00	200	200
6.00% Series C	2,000,000	100.00	200	—
Total			$ 929	$ 729

The Series A preference stock, issued in 2005, may not be redeemed prior to April 30, 2010. After April 30, 2010, SCE may, at its option, redeem the shares in whole or in part and the dividend rate may be adjusted. The Series B preference stock, issued in 2005, may not be redeemed prior to September 30, 2010. After September 30, 2010, SCE may, at its option, redeem the shares in whole or in part. The Series C preference stock, issued in 2006, may not be redeemed prior to January 31, 2011. After, January 31, 2011, SCE may, at its option, redeem the shares in whole or in part. No preference stock not subject to mandatory redemption was redeemed in the last three years.

Note 16. Mohave Shutdown

Mohave obtained all of its coal supply from the Black Mesa Mine in northeast Arizona, located on lands of the Tribes. This coal was delivered from the mine to Mohave by means of a coal slurry pipeline, which required water from wells located on lands belonging to the Tribes in the mine vicinity. Uncertainty over post-2005 coal and water supply has prevented SCE and other Mohave co-owners from making approximately $1.1 billion in Mohave-related investments (SCE's share is $605 million), including the installation of enhanced pollution-control equipment required by a 1999 air-quality consent decree in order for Mohave to operate beyond 2005. Accordingly, the plant ceased operations, as scheduled, on December 31, 2005, consistent with the provisions of the consent decree.

On June 19, 2006, SCE announced that it had decided not to move forward with its efforts to return Mohave to service. SCE's decision was not based on any one factor, but resulted from the conclusion that in light of all the significant unresolved challenges related to returning the plant to service, the plant could not be returned to service in sufficient time to render the necessary investments cost-effective for SCE's customers. Two of the other Mohave co-owners, Nevada Power Company and the DWP, made similar announcements, while the fourth co-owner, SRP, has announced that it is pursuing the possibility of putting together a successor owner group, which would include SRP, to pursue continued coal operations. On February 6, 2007, however, SRP issued a press release announcing that it was discontinuing its efforts to return Mohave to service. All of the co-owners are continuing to evaluate the range of options for disposition of the plant, which conceivably could include, among other potential options, sale of the plant "as is" to a power plant operator, decommissioning and sale of the property to a developer, and decommissioning and apportionment of the land among the owners. At this time, SCE continues to work with the water and coal suppliers to the plant to determine if more clarity around the provision of such services can be provided to any potential acquirer.

Following the suspension of Mohave operations at the end of 2005, the plant's workforce was reduced from over 300 employees to approximately 65 employees by the end of 2006. SCE recorded $15 million in termination costs during the year for Mohave (SCE's share). These termination costs were deferred in a balancing account authorized in the 2006 GRC decision. SCE expects to recover this amount in the balancing account in future rate-making proceedings.

As of December 31, 2006, SCE had a Mohave net regulatory asset of approximately $81 million representing its net unamortized coal plant investment, partially offset by revenue collected for future removal costs. Based on the 2006 GRC decision, SCE is allowed to continue to earn its authorized rate of return on the Mohave investment and receive rate recovery for amortization, costs of removal, and operating and maintenance expenses, subject to balancing account treatment, during the three-year 2006 rate case cycle. On October 5, 2006, SCE submitted a formal notification to the CPUC regarding the out-of-service status of Mohave, pursuant to a California statute requiring such notice to the CPUC whenever a plant has been out of service for nine consecutive months. SCE also reported to the CPUC on Mohave's status numerous times previously. Pursuant to the statute, the CPUC may institute an investigation to determine whether to reduce SCE's rates in light of Mohave's changed status. At this time, SCE does not anticipate that the CPUC will order a rate reduction. In the past, the CPUC has allowed full recovery of investment for similarly situated plants. However, in a December 2004 decision, the CPUC noted that SCE would not be allowed to recover any unamortized plant balances if SCE could not demonstrate that it took all steps to preserve the "Mohave-open" alternative. SCE believes that it will be able to demonstrate that SCE did everything reasonably possible to return Mohave to service, which it further believes would permit its unamortized costs to be recovered in future rates. However, SCE cannot predict the outcome of any future CPUC action.

Note 17. Business Segments

SCE's reportable business segments include the rate-regulated electric utility segment and the VIE segment. The VIEs were consolidated as of March 31, 2004. The VIEs are gas-fired power plants that sell both electricity and steam. The VIE segment consists of non-rate-regulated entities. SCE's management has no control over the resources allocated to the VIE segment and does not make decisions about its performance. Additional details on the VIE segment are shown under the heading "Variable Interest Entities" in Note 14.

SCE's business segment information including all line items with VIE activities is:

In millions	Electric Utility	VIEs	Eliminations	SCE
Balance Sheet Items as of December 31, 2006:				
Cash and equivalents	$ 5	$ 78	$ —	$ 83
Accounts receivable–net	893	141	(95)	939
Inventory	218	14	—	232
Other current assets	50	4	—	54
Nonutility property–net of depreciation	727	319	—	1,046
Other long-term assets	481	7	—	488
Total assets	25,642	563	(95)	26,110
Accounts payable	809	142	(95)	856
Other current liabilities	622	2	—	624
Long-term debt	5,117	54	—	5,171
Asset retirement obligations	2,735	14	—	2,749
Minority interest	—	351	—	351
Total liabilities and shareholder's equity	$ 25,642	$ 563	$ (95)	$ 26,110
Balance Sheet Items as of December 31, 2005:				
Cash	$ 23	$ 120	$ —	$ 143
Accounts receivable–net	794	174	(119)	849
Inventory	202	18	—	220
Other current assets	88	4	—	92
Nonutility property–net of depreciation	741	345	—	1,086
Other long-term assets	493	10	—	503
Total assets	24,151	671	(119)	24,703
Accounts payable	813	204	(119)	898
Other current liabilities	721	2	—	723
Long-term debt	4,615	54	—	4,669
Asset retirement obligations	2,608	13	—	2,621
Minority interest	—	398	—	398
Total liabilities and shareholder's equity	$ 24,151	$ 671	$ (119)	$ 24,703

In millions	Electric Utility	VIEs	Eliminations*	SCE
Income Statement Items for the Year-Ended December 31, 2006:				
Operating revenue	$ 9,926	$ 1,137	$ (751)	$ 10,312
Fuel	389	723	—	1,112
Purchased power	4,160	—	(751)	3,409
Other operation and maintenance	2,575	103	—	2,678
Depreciation, decommissioning and amortization	990	36	—	1,026
Total operating expenses	8,344	862	(751)	8,455
Operating income	1,582	275	—	1,857
Interest income	58	—	—	58
Interest expense – net of amounts capitalized	400	—	—	400
Income tax expense	438	—	—	438
Minority interest	—	275	—	275
Net income	$ 827	—	—	$ 827
Income Statement Items for the Year-Ended December 31, 2005:				
Operating revenue	$ 9,038	$ 1,397	$ (935)	$ 9,500
Fuel	269	924	—	1,193
Purchased power	3,557	—	(935)	2,622
Other operation and maintenance	2,421	102	—	2,523
Depreciation, decommissioning and amortization	878	37	—	915
Total operating expenses	7,743	1,063	(935)	7,871
Operating income	1,295	334	—	1,629
Interest income	44	—	—	44
Interest expense – net of amounts capitalized	360	—	—	360
Income tax expense	292	—	—	292
Minority interest	—	334	—	334
Net income	$ 749	—	—	$ 749
Income Statement Items for the Year-Ended December 31, 2004:				
Operating revenue	$ 8,163	$ 954	$ (669)	$ 8,448
Fuel	232	578	—	810
Purchased power	3,001	—	(669)	2,332
Other operation and maintenance	2,389	68	—	2,457
Depreciation, decommissioning and amortization	832	28	—	860
Total operating expenses	6,430	674	(669)	6,435
Operating income	1,733	280	—	2,013
Interest income	20	—	—	20
Interest expense – net of amounts capitalized	409	—	—	409
Income tax expense	438	—	—	438
Minority interest	—	280	—	280
Net income	$ 921	—	—	$ 921

* VIE segment revenue includes sales to the electric utility segment, which is eliminated in revenue and purchased power in the consolidated statements of income.

Note 18. Acquisitions

In March 2004, SCE acquired Mountainview Power Company LLC, which consisted of a power plant in early stages of construction in Redlands, California. SCE recommenced full construction of the approximately $600 million project. The Mountainview plant is fully operational.

Note 19. Quarterly Financial Data (Unaudited)

	2006					2005				
In millions	**Total(1)**	**Fourth**	**Third**	**Second**	**First**	Total(1)	Fourth	Third	Second	First
Operating revenue	**$ 10,312**	**$ 2,494**	**$ 3,079**	**$ 2,521**	**$ 2,217**	$ 9,500	$ 2,306	$ 3,084	$ 2,203	$ 1,908
Operating income	**1,857**	**315**	**673**	**536**	**332**	1,629	345	568	388	328
Net income	**827**	**171**	**276**	**247**	**133**	749	163	287	166	132
Net income available for common stock	**776**	**158**	**263**	**234**	**121**	725	153	280	161	131
Common dividends declared	**240**	**60**	**60**	**60**	**60**	285	71	143	71	—

(1) As a result of rounding, the total of the four quarters does not always equal the amount for the year.

Dollars in millions	**2006**	2005	2004	2003	2002
Income statement data:					
Operating revenue	**$ 10,312**	$ 9,500	$ 8,448	$ 8,854	$ 8,706
Operating expenses	**8,455**	7,871	6,435	7,276	6,588
Purchased-power expenses	**3,409**	2,622	2,332	2,786	2,016
Income tax expense	**438**	292	438	388	642
Provisions for regulatory adjustment clauses – net	**25**	435	(201)	1,138	1,502
Interest expense – net of amounts capitalized	**400**	360	409	457	584
Net income from continuing operations	**827**	749	921	882	1,247
Net income	**827**	749	921	932	1,247
Net income available for common stock	**776**	725	915	922	1,228
Ratio of earnings to fixed charges	**3.98**	3.79	4.40	3.80	4.20

Balance sheet data:					
Assets	**$ 26,110**	$ 24,703	$ 23,290	$ 21,771	$ 36,058
Gross utility plant	**20,734**	19,232	17,981	16,991	16,232
Accumulated provision for depreciation and decommissioning	**4,821**	4,763	4,506	4,386	4,057
Short-term debt	**—**	—	88	200	—
Common shareholder's equity	**5,447**	4,930	4,521	4,355	4,384
Preferred and preference stock:					
Not subject to mandatory redemption	**929**	729	129	129	129
Subject to mandatory redemption	**—**	—	139	141	147
Long-term debt	**5,171**	4,669	5,225	4,121	4,525
Capital structure:					
Common shareholder's equity	**47.2%**	47.7%	45.1%	49.8%	47.7%
Preferred stock:					
Not subject to mandatory redemption	**8.0%**	7.1%	1.3%	1.5%	1.4%
Subject to mandatory redemption		—	1.4%	1.6%	1.6%
Long-term debt	**44.8%**	45.2%	52.2%	47.1%	49.3%

The selected financial data was derived form SCE's audited financial statements and is qualified in its entirety by the more detailed information and financial statements, including notes to these financial statements, included in this annual report.

[THIS PAGE INTENTIONALLY LEFT BLANK]

[THIS PAGE INTENTIONALLY LEFT BLANK]

Board of Directors

John E. Bryson [3,6]
Chairman of the Board,
President and
Chief Executive Officer,
Edison International;
Chairman of the Board, Southern
California Edison Company;
A director from 1990-1999;
2003 to present

France A. Córdova [4,5]
Chancellor,
University of California, Riverside
Riverside, California
A director since 2004

Charles B. Curtis [4,5]
President and Chief Operating Officer
Nuclear Threat Initiative
(private foundation dealing with
national security issues)
Washington, D.C.
A director since 2006

Alan J. Fohrer [3,6]
Chief Executive Officer,
Southern California Edison Company
A director since 2002

Bradford M. Freeman [1,2,5]
Founding Partner,
Freeman Spogli & Co.
(private investment company)
Los Angeles, California
A director since 2002

Luis G. Nogales [1,2,4,7]
Managing Partner,
Nogales Investors, LLC
(private equity investment company)
Los Angeles, California
A director since 1993

Ronald L. Olson [3,4]
Senior Partner,
Munger, Tolles and Olson (law firm)
Los Angeles, California
A director since 1995

James M. Rosser [3,4]
President,
California State University, Los Angeles
Los Angeles, California
A director since 1985

Richard T. Schlosberg, III [1,2,5]
Retired President and
Chief Executive Officer,
The David and Lucile Packard
Foundation (private family foundation)
San Antonio, Texas
A director since 2002

Robert H. Smith [1,2,5]
Robert H. Smith Investments
and Consulting
(banking and financial-related
consulting services)
Pasadena, California
A director since 1987

Thomas C. Sutton [1,2,3]
Chairman of the Board and
Chief Executive Officer,
Pacific Life Insurance Company
Newport Beach, California
A director since 1995

1 Audit Committee
2 Compensation and Executive Personnel Committee
3 Executive Committee
4 Finance Committee
5 Nominating/Corporate Governance Committee
6 Pricing Committee
7 Pricing Committee (Alternate Member)

Management Team

John E. Bryson
Chairman of the Board

Alan J. Fohrer
Chief Executive Officer

John R. Fielder
President

Polly L. Gault
Executive Vice President,
Public Affairs

Bruce C. Foster
Senior Vice President,
Regulatory Operations

Cecil R. House
Senior Vice President,
Safety and Operations Support

Ronald L. Litzinger
Senior Vice President,
Transmission and Distribution

Thomas M. Noonan
Senior Vice President and
Chief Financial Officer

Barbara J. Parsky
Senior Vice President,
Corporate Communications

Stephen E. Pickett
Senior Vice President and
General Counsel

Pedro J. Pizarro
Senior Vice President,
Power Procurement

Richard M. Rosenblum
Senior Vice President,
Generation and Chief Nuclear Officer

Mahvash Yazdi
Senior Vice President,
Business Integration and
Chief Information Officer

Lynda L. Ziegler
Senior Vice President,
Customer Service

Jeffrey L. Barnett
Vice President,
Tax

Robert C. Boada
Vice President and Treasurer

William L. Bryan
Vice President,
Business Customer Division

Kevin R. Cini
Vice President,
Energy Supply and Management

Ann P. Cohn
Vice President and
Associate General Counsel

Jodi M. Collins
Vice President,
Information Technology

Diane L. Featherstone
Vice President and General Auditor

Harry B. Hutchison
Vice President,
Customer Service Operations

Akbar Jazayeri
Vice President,
Revenue and Tariffs

Walter J. Johnston
Vice President,
Power Delivery

Brian Katz
Vice President,
Nuclear Oversight and
Regulatory Affairs

James A. Kelly
Vice President,
Engineering and Technical Services

R. W. (Russ) Krieger, Jr.
Vice President,
Power Production

Barbara E. Mathews
Vice President,
Associate General Counsel,
Chief Governance Officer, and
Corporate Secretary

Kevin M. Payne
Vice President,
Enterprise Resource Planning

Frank J. Quevedo
Vice President,
Equal Opportunity

James T. Reilly
Vice President,
Nuclear Engineering and
Technical Services

Tommy Ross
Vice President,
Public Affairs

Kenneth S. Stewart
Vice President and
Chief Ethics and Compliance Officer

Linda G. Sullivan
Vice President and
Controller

Raymond W. Waldo
Vice President,
Nuclear Generation

Shareholder Information

Annual Meeting

The annual meeting of shareholders will be held on Thursday, April 26, 2007, at 10:00 a.m., Pacific Time, at the Pacific Palms Conference Resort; One Industry Hills Parkway, City of Industry, California 91744.

Corporate Governance Practices

A description of SCE's corporate governance practices is available on our Web site at www.edisoninvestor.com. The SCE Board Nominating/Corporate Governance Committee periodically reviews the Company's corporate governance practices and makes recommendations to the Company's Board that the practices be updated from time to time.

Stock and Trading Information

Preferred Stock and Preference Stock
SCE's 4.08%, 4.24%, 4.32% and 4.78% Series of $25 par value cumulative preferred stock are listed on the American Stock Exchange. Previous day's closing prices, when stock was traded, are listed in the daily newspapers under the American Stock Exchange. Shares of SCE's Series A, Series B and Series C preference stock are not listed on an exchange.

Transfer Agent and Registrar

Wells Fargo Bank, N.A., which maintains shareholder records, is the transfer agent and registrar for SCE's preferred and preference stock. Shareholders may call Wells Fargo Shareowner Services, (800) 347-8625, between 7 a.m. and 7 p.m. (Central Time), Monday through Friday, to speak with a representative (or to use the interactive voice response unit 24 hours a day, seven days a week) regarding:

- stock transfer and name-change requirements;
- address changes, including dividend payment addresses;
- electronic deposit of dividends;
- taxpayer identification number submissions or changes;
- duplicate 1099 and W-9 forms;
- notices of, and replacement of, lost or destroyed stock certificates and dividend checks; and
- requests for access to online account information.

Inquiries may also be directed to:

Mail
Wells Fargo Bank, N.A.
Shareowner Services Department
161 North Concord Exchange Street
South St. Paul, MN 55075-1139

Fax
(651) 450-4033
Wells Fargo Shareowner Services℠
www.wellsfargo.com/shareownerservices

Web Address
www.edisoninvestor.com
Online account information
www.shareowneronline.com

This annual report is printed on recycled paper.

SOUTHERN CALIFORNIA
EDISON
An EDISON INTERNATIONAL Company

2244 Walnut Grove Avenue
Rosemead, California 91770
www.sce.com

END