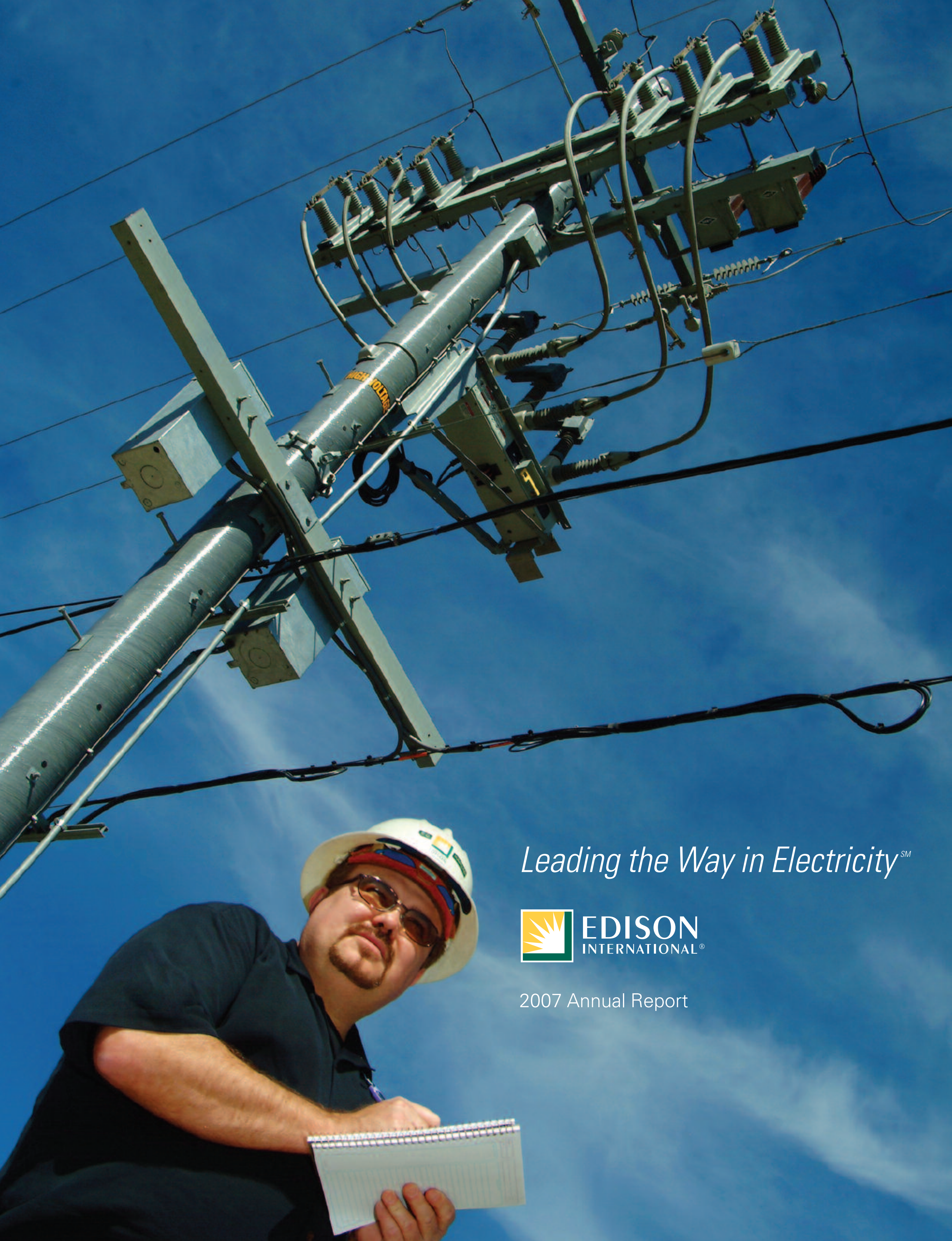


Leading the Way in Electricity[SM]

EDISON
INTERNATIONAL®

2007 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

Cover photo: Ed Kamiab, Lead Project Engineer, Circuit of the Future, Southern California Edison – standing next to a new, modular power pole made from lighter-weight composite materials, featuring equipment that utilizes advanced smart-grid technologies developed by Southern California Edison.

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

Letter to Shareholders

Edison International performed well in 2007, throughout the company and across the country. From developing the nation's most advanced smart-grid technology in Southern California, to managing an expanding portfolio of wind energy projects in eight states, to achieving the best fleet safety performance in company history at our power plants in Illinois, to earning strong returns from energy trading operations in Boston, your company achieved significant operational and financial success during the year.

At Southern California Edison (SCE), now California's largest electric utility, we completed a record amount of infrastructure investment and significantly advanced several large initiatives that will over the next five years strengthen the electric system, improve customer service and help meet state environmental objectives. At our independent power business, Edison Mission Group (EMG), we achieved excellent earnings while continuing to build a foundation for future growth that is more diversified and greener.

Operating our businesses well in 2007 produced solid financial results. Core earnings[1] were $3.69 per share, 20 percent above last year. Total shareholder return in 2007 was 20 percent. That exceeds the indices to which we generally compare ourselves, including the Philadelphia Utility Index (up 19 percent during the year), the S&P 500 (up five and a half percent) and the other California utilities (up three percent). And, for the second year in a row, the Edison Electric Institute recognized Edison International as having the best total shareholder return among all U.S. investor-owned utilities over the prior five years.

A Year of Accomplishment at SCE

This was the third consecutive year of dramatically stepped-up investment in the distribution system, and the SCE team met the very aggressive targets we set. To cite only a few examples: we replaced nearly 30 miles of aging underground cable and nearly 9,000 utility poles. We broke ground on the first new service center in more than 20 years, to better serve customers in the growing Inland Empire region.

[1] Reported earnings, which include net non-core charges of $0.36 largely due to a favorable EMG debt restructuring, were $3.33 per share.

We rehabilitated the 27 worst performing electricity distribution circuits to improve reliability and built 43 new circuits to keep up with sustained load growth.

In October, with support from the U.S. Department of Energy, SCE engineers in a landmark advance took smart-grid technology out of the laboratory and created the most advanced distribution circuit in the nation, serving 1,400 customers in the San Bernardino area. This "Circuit of the Future" will make power outages fewer and shorter, as digital technology identifies, analyzes and isolates potential service disruptions in milliseconds, before they become significant power outages. Our goal is to create a power delivery system that is as smart as the devices our customers plug into it. This project is an important start.

Our goal is to create a power delivery system that is as smart as the devices our customers plug into it.

SCE also enhanced its ability to meet record peak electricity demand in 2007. After the record-breaking Southern California heat of summer 2006, Governor Schwarzenegger and the California Public Utilities Commission (CPUC) challenged SCE to add 600 megawatts of supply capacity to the system in time for summer 2007. Starting from scratch, the SCE team identified sites, secured permits, designed and then built within 11 months four "peaking" generation plants to supply reserve power in key locations. This work, along with a 60 percent increase in our residential air conditioner cycling demand-side management program and a fast-track contracting process that made possible the refurbishing of a dormant gas-fired power plant, allowed SCE to meet the goal on schedule.

A Strong Foundation for SCE Growth Through 2012

Our business is one of long-term horizons. So although SCE's completion of more than $2.2 billion of infrastructure improvement in 2007 was a significant achievement, the largest accomplishments of the year under Al Fohrer's consistently excellent leadership were those that strengthened our foundation for future growth.

Even with the record infrastructure replacement investment of 2007 behind us, SCE is still not at what engineers consider a "steady state" replacement rate to ensure current reliability levels. Even if customer growth in Southern California slows due to a potentially weakening economy, we will still play catch-up for the foreseeable future on the enormous volume of work required to upgrade the electric system and replace aging infrastructure.

When SCE serves customers well and efficiently manages operations, shareholders have the opportunity to benefit. Work completed in 2007 increased our earning asset base to an all-time high of approximately $11.7 billion. If we execute our plan for approximately $19 billion in continued infrastructure investment over the next five years, and continue to receive the necessary regulatory support, the SCE earnings base should nearly double by 2012.

In 2007, SCE substantially advanced major multi-year projects comprising more than 75 percent of that $19 billion infrastructure investment plan.

First, we received regulatory approval for the first phase of the Tehachapi Renewable Transmission Project and began construction this January. Tehachapi, the first new transmission line SCE has built in more than 20 years, will connect to the electric grid one of the nation's richest areas for new renewable generation. Transmission lines – the interstate highways of the electric system – stretch for miles through multiple communities and jurisdictions. Securing all the necessary permits is very time-consuming and difficult. One of our disappointments this year was the Arizona Corporation Commission's rejection of the Devers-Palo Verde 2 transmission line, which would expand transfer capacity between California and the Southwest. This project would serve one of the two areas in the United States designated by the U.S. Department of Energy as a "National Interest Electric Transmission Corridor." We will continue to work hard to find a means to move forward on this essential regional transmission line.

Second, our Edison SmartConnect™ advanced meter initiative, which in 2006 was a highly promising concept, became in 2007 a demonstrated commercial reality. The project team completed a successful field test of 2,800 SCE customer meters and selected the principal technology and telecommunications vendor. With regulatory approval, 5.3 million of these meters will be installed over the next five years.

Third, our team at San Onofre Nuclear Generating Station met all milestones to remain on schedule and on budget with the complex task of replacing the plant's steam generators. Fabrication of the first of the massive 640-ton steam generators is nearing completion and will be delivered in 2008. This project should allow the plant, Southern California's largest power source, to operate potentially for an additional 40 years. The value of this reliable source of carbon-free generation has never been more apparent.

Finally, SCE last year filed its 2009 - 2011 General Rate Case application with the CPUC. These proceedings are a major undertaking; our full submission will total more than 65,000 pages of careful documentation. The outcome will largely determine the extent of our ability to continue the expansion and modernization of the SCE electric grid to meet our customers' needs.

A Diversified Growth Platform at EMG

At EMG, we took further steps during 2007 to capture increasing margins from our coal-fired generation fleet, grow our wind energy business, broaden our marketing and trading platform, and strengthen the balance sheet to make possible further hedging and strategic investments.

In May, the EMG team increased credit strength by refinancing $2.7 billion of debt. We were able to lock in historically low interest rates, longer maturities and other highly favorable terms.

EMG placed four wind projects into commercial operation, and began construction on an additional seven projects. As a result, EMG's wind portfolio in operation and construction now exceeds 1,000 megawatts. In addition, the development team nearly doubled EMG's project pipeline during the year to more than 5,000 megawatts of potential investments.

The wind energy business is not without challenges. Competition is increasing, project costs are escalating, and we are working with suppliers to resolve delivery and equipment issues. Nonetheless, public support for renewable sources of electricity continues to grow, and investors are increasingly recognizing the value we are developing in this wind business.

The energy marketing and trading business within EMG has been a consistent performer, with trading margins exceeding $460 million over the last three years. This is a tightly focused business for us, grounded in our everyday experience selling and hedging the power generated by our own plants. We began generation capacity trading in 2007, and added the expertise and systems to begin trading in new wholesale markets in California and Texas. We see opportunities within our risk disciplines to further grow this business.

In May, the EMG team increased credit strength by refinancing $2.7 billion of debt. We were able to lock in historically low interest rates, longer maturities and other highly favorable terms. The decision looks even better today: We would not be able to complete such a refinancing at all in current credit markets.

Additional steps in 2007 increased future revenue and decreased volatility. Reflecting tighter projected power/demand balance in Eastern and Midwest wholesale markets, the EMG team sold capacity forward for each of the next three years at increasingly higher values.

It is inherently more difficult to project an earnings outlook for a competitive generation business such as EMG than for a utility such as SCE. What is clear, however, is that the accomplishments of 2007 put EMG in a stronger position going forward.

Environmental Priorities as a Driver of our Business

National concern about protecting the environment, particularly from greenhouse gas emissions, has sharply intensified over the past year. This will have a significant effect on our company, most notably with respect to our fleet of competitive coal-fired generation at EMG. At the same time, it will provide further support for the greener elements of our business.

Meeting growing energy needs in an environmentally sensitive way has been a high priority for Edison International and the state of California for more than three decades. Our long experience and leadership in energy efficiency, renewable generation and electric transportation position us well to help lead the way, to the benefit of both our customers and our shareholders.

Meeting growing energy needs in an environmentally sensitive way has been a high priority for Edison International and the state of California for more than three decades.

Energy efficiency is the fastest and most cost-effective means to achieve meaningful reductions in greenhouse gas emissions. California already sets the national standard: Per capita electricity use in the state has remained essentially flat since the mid-1970s, while consumption in the rest of the United States has increased by 50 percent. In 2007, the CPUC raised the bar even higher by adopting a nationally significant incentive mechanism that encourages utilities to view investments in energy efficiency programs as good business, similar to investments in “steel in the ground” generation facilities. In short, the CPUC now allows the state’s utilities to earn a return when they cost-effectively meet new and higher targets for energy efficiency savings.

The expanded development of renewable power sources is another key element of any serious effort to reduce greenhouse gas emissions. SCE remains the nation’s leading utility in the percent of its power supplied by renewable resources, and EMG is becoming a leader in building new wind energy projects.

We are championing the benefits of renewable power while offering a clear-eyed perspective on the challenges that must be addressed when an increasing percentage of a region's generation comes from intermittent, less predictable renewable sources.

Energy efficiency is the fastest and most cost-effective means to achieve meaningful reductions in greenhouse gas emissions.

Further in the future, but no less critical to meeting ambitious environmental goals, are new clean sources of baseload generation. Clean coal and carbon sequestration technologies are at early stages of development and challenges abound. Cost projections have very significantly increased in the past year and critical issues, such as regulatory standards and legal protections for carbon storage, have yet to be seriously addressed. Just a little further along, the early stages of a new generation of nuclear power is beginning to move forward. This too will require proven regulatory processes and the clearer resolution of key issues such as waste storage. The national interest in new large-scale generation with zero- or low-carbon emissions requires that both clean coal and nuclear technologies be intensely pursued. At both our utility and our competitive generation businesses, we are committed to playing a meaningful role in this effort.

Electricity as a fuel for transportation is on the cusp of a breakthrough. Based on a number of announcements by major automakers, we should see plug-in electric hybrid vehicles on the roads in the next five years. The environmental benefits of electric motors versus gasoline-powered internal combustion engines are clear. Electricity as a fuel is cost-effective, significantly less than the cost of gasoline equivalent. And electricity is the only alternative transportation fuel with a national infrastructure already in place and connected to every garage. The U.S. Department of Energy estimates that more than 70 percent of the cars and light trucks on the road in the United States today could be fueled by excess capacity in the national electric grid. In the long term, as plug-in vehicles increase in volume, using the grid's off-peak capacity at night to charge these vehicles may actually help lower customer electricity rates by increasing the productivity of the electricity grid.

At SCE, we have supported electric transportation for the last two decades. We are currently working in tight partnership with major automakers to jointly advance the national interest in clean transportation. Our Electric Vehicle Technical Center, unique in the utility industry, evaluates all forms of electro-drive technology. We have ongoing evaluation and demonstration programs supporting airport and sea port electrification; truckstop electrification; battery electric vehicles; plug-in hybrid electric vehicles; and fuel cell electric vehicles.

Electricity is the only alternative transportation fuel with a national infrastructure already in place and connected to every garage.

Greenhouse Gas Policy an Uncertainty

As public support for limits on greenhouse gas emissions continues appropriately to increase and become more focused, it is likely that new federal legislation will be adopted within the next two or three years. Since 2000, we have already reduced the carbon intensity (a common industry measure of greenhouse gas emissions) of Edison International power generation facilities by seven percent, and more reductions are planned. However, until public policy on this important issue becomes more predictable, large uncertainties with major potential consequences in cost and supply reliability will exist for much of the nation's electricity system and for power generators, including our company.

We are actively working with public officials and key industry and environmental groups to address this issue. We will continue to advocate thoughtful, fact-based approaches to meaningfully reduce carbon emissions and intensity and, at the same time, to constrain to the extent reasonably possible the large regional and national economic impacts that will accompany an accelerated transformation to a low-carbon economy. The development of advanced, cost-effective environmental control technologies will be essential to achieve both greenhouse gas reduction and the minimization of substantial economic dislocations. Edison International is committed to being a participant in that effort.

An Intense Focus on People and Culture

One of the enduring lessons from my nearly eighteen years as a chief executive is the power of a company culture to make a major difference in whether employees find ways to improve year after year, meet and overcome large challenges, and achieve consistently excellent results.

After our company emerged successfully from the twin challenges of the California Power Crisis and the financial collapse of the independent power business – where a deeply ingrained culture of perseverance and "keeping the lights on" helped us find a path through when others faltered – we conducted a fresh assessment of ourselves. Mostly we were proud of what we saw, but there was room for improvement. So we began a focused effort to strengthen our culture in some key areas. Engaging employees at all levels, we have mounted over the past three years an intense process to become yet stronger. Last year, we articulated a new statement of company vision, Leading the Way in Electricity,SM setting forth our values and operating priorities. We are formally reinforcing in our human resources processes that performance consistent with these values is key to individual career advancement and shared business success. In the past year, recognizing that mid-level managers are often at least as influential as senior executives in shaping culture, we brought interactive leadership development workshops based on the company values to more than 1,500 managers and supervisors.

Integrity builds trust and confidence among us and on the part of others dealing with us.

Certain areas are receiving particular focus. One of them is employee and public safety. So for example the EMG leadership team in 2007 personally took the message to every generating station that safety can never be compromised. And at SCE, "Safety Congresses" brought front-line employees and management together in a common effort to see that every employee goes home safely each night.

Other points of emphasis are teamwork and continuous improvement, both critical to our long-term operational success. At EMG in the past year, cross-discipline task forces were employed to refine strategic direction and make recommendations on key business issues. At SCE, a very large enterprise resource planning implementation is breaking down silos and bringing together employees of diverse skills and experience to improve the business as a whole. These projects, and others like them, create high performing teams drawn from across departments and locations, giving our employees new opportunities to learn and excel.

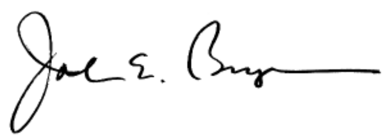
Integrity is the cornerstone. Integrity builds trust and confidence among us and on the part of others dealing with us. It attracts and inspires excellent employees. We instituted a best-practice ethics and compliance program in 2005 and have carried it forward. Nearly all of our employees completed enhanced ethics and compliance training in 2007. Surveys suggest our vigorous efforts in this area over the last three years are taking hold, but we cannot allow gains to lead to complacency.

Cultures are built over long periods of time. Making them yet stronger and more productive is not achieved overnight. Some skepticism is inevitable. If our company's leadership fails to match words with actions, the effort will certainly fail. Companies, like individuals, are certainly imperfect; but our culture at Edison International meets in most respects a high standard. Where improvement was most needed we are making meaningful progress.

Looking Ahead

Edison International's foundation for continued future growth was strengthened in many ways during 2007. Among the most significant was the announcement that Ted Craver will succeed me as chairman, president and chief executive officer upon my retirement at the end of this July. Over the past 11 years, Ted has consistently brought a powerful work ethic, keen intelligence and intense focus on achieving success to a series of significant responsibilities across the company. I am confident that under Ted's leadership, and with the support of our strong senior management team, our company will continue to succeed and grow.

I would like to thank the members of our Board, the shareholders of Edison International and all the employees past and present who have supported and counseled me over the past two decades. There are few experiences more rewarding than having successfully faced large challenges and taken bold initiatives with a strong team. It has been an honor and a pleasure to lead this great company.



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

March 1, 2008

John Bryson Ted Craver

16% OF SCE'S

ENERGY PORTFOLIO

IS GENERATED FROM RENEWABLE SOURCES. SCE IS THE NATION'S LEADER IN PURCHASING RENEWABLE ENERGY – 12.5 BILLION KILOWATT HOURS IN 2007.

A legacy of

Providing Renewable Energy

From the mountain passes of Southern California, to the plains of Texas, to the farmlands of Minnesota, we are producing and delivering more clean wind energy every year to power consumers across the country. With our Southern California Edison and Edison Mission Group subsidiaries, Edison International is one of the nation’s leaders in developing, generating and buying wind energy — a renewable source of electricity that is rapidly growing across the country.

MORE THAN
5 MILLION METERS
WILL BE INSTALLED THROUGH 2012

At the forefront of an energy revolution:
Edison SmartConnect™

Imagine receiving messages on your home thermostat, alerting you to when demand for power is high, so that you can adjust your energy use. Imagine knowing your exact electricity usage and cost at any point in time. Imagine your electric meter communicating wirelessly with appliances in your home, helping you to manage your energy consumption. Edison SmartConnect,™ the nation's most advanced smart metering system, will make these possibilities a reality for Southern California Edison customers.

Reliable Power Delivery Systems

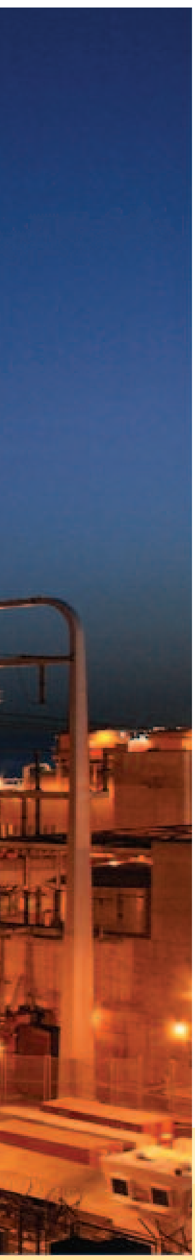
Sophisticated home electronics and an increasingly high-tech economy mean that more than ever before, customers rely on SCE to provide reliable electricity service. SCE is responding with a large multi-year infrastructure investment program to upgrade and modernize the electricity grid. At the same time, SCE is a leader in the application of advanced "smart grid" technology – because a high-tech world can no longer afford a low-tech electricity grid.

The San Onofre Nuclear Generating Station achieved a major milestone in 2007 – the first of two reactor units currently operating at the site has provided 25 years of safe, virtually carbon-free, power generation. The facility plays a vital role in meeting Southern California's growing need for electricity while avoiding conventional air pollutant emissions and greenhouse gas emissions. We are proud of San Onofre's production record, generating 350 billion kilowatt hours of electricity since 1982, enough energy to meet the power needs of approximately one million Southern California homes during the entire 25-year period.

25 years of producing Clean Energy

Generating Power Reliably

Edison Mission Group's fleet of coal-fired generation plants in Illinois and Pennsylvania helps ensure a reliable supply of electricity in a 13-state region, extending from the Atlantic seaboard westward to Illinois. Generation targets were exceeded by 1.4 million megawatt hours during 2007. This accomplishment reflects the companywide focus on redesigning business practices to gain greater efficiencies and improve productivity.



272

CONSECUTIVE DAYS

OF UNINTERRUPTED POWER PRODUCTION AT

HOMER CITY UNIT 2

– A NEW RECORD

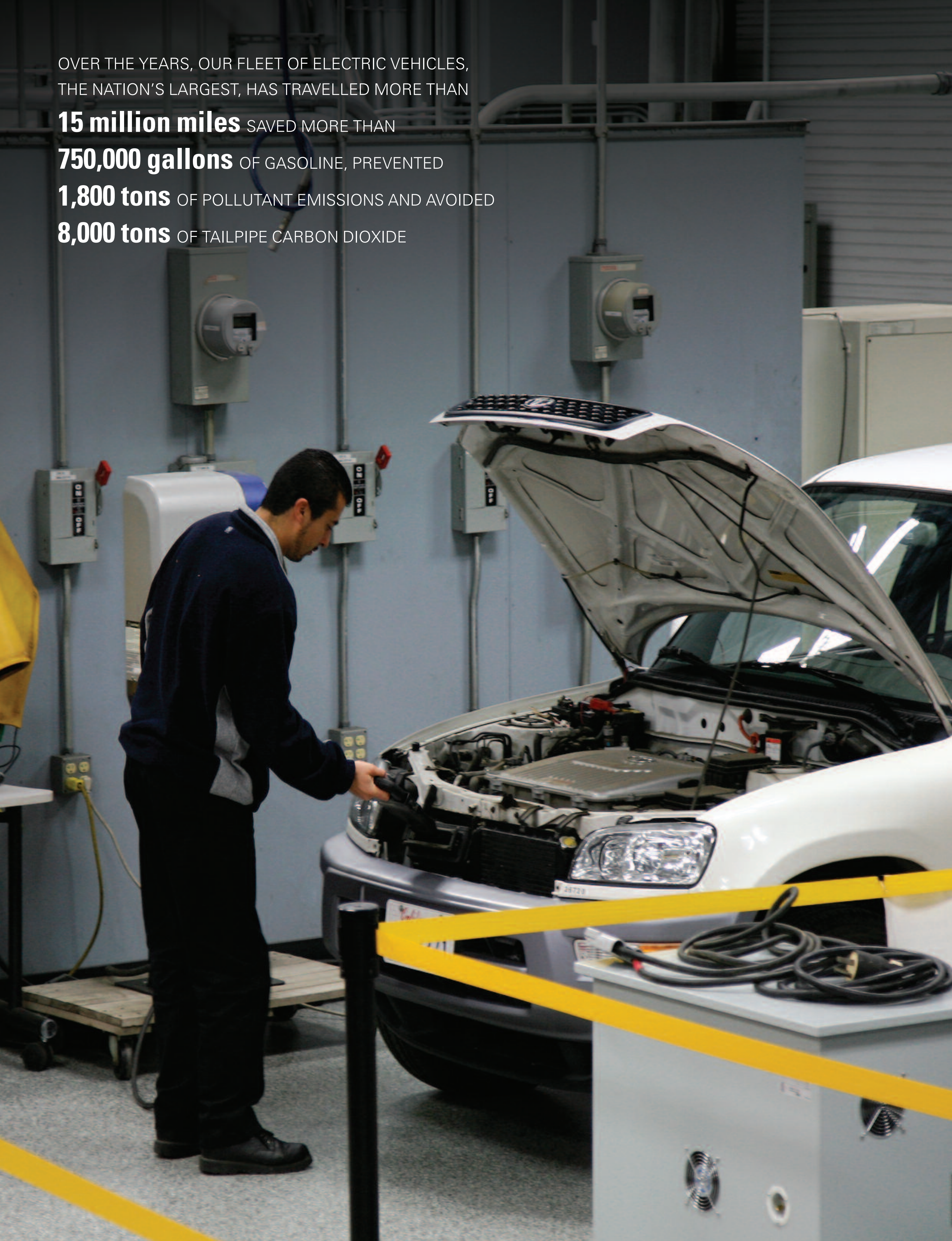
EMG ACHIEVED A
23%
IMPROVEMENT
IN RECORDABLE INJURIES
IN 2007 OVER THE PREVIOUS YEAR

Committed to Safety

Operating an injury-free workplace is more than a corporate goal for Edison International. It is a commitment to our employees. Safety is a fundamental operating priority for us – in every power plant, office, call center, field operation and warehouse. We integrate safety into our daily operations and continuously work to strengthen our safety culture. Our obligation is to make sure that every individual leaves the workplace unhurt – anything less is unacceptable.


3

OVER THE YEARS, OUR FLEET OF ELECTRIC VEHICLES, THE NATION'S LARGEST, HAS TRAVELLED MORE THAN **15 million miles** SAVED MORE THAN **750,000 gallons** OF GASOLINE, PREVENTED **1,800 tons** OF POLLUTANT EMISSIONS AND AVOIDED **8,000 tons** OF TAILPIPE CARBON DIOXIDE



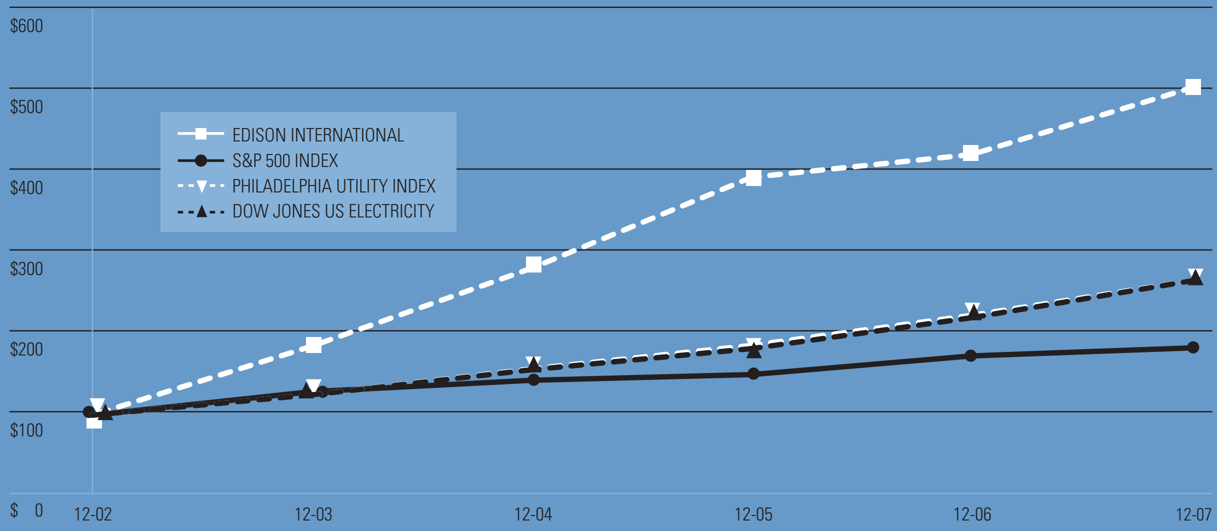
For more than two decades, we've supported Electric Transportation

We envision a future where our customers no longer just fill their cars at the gas pump. They fuel them by plugging into the electricity grid too — transforming the automobiles and advanced batteries of tomorrow into an integral part of the nation's future energy system. Southern California Edison is a leader in evaluating and demonstrating plug-in vehicles and advanced energy storage technologies. We have a long history of building industry-leading partnerships with major automakers, battery manufacturers and federal and state governments. We are committed to helping build an electric transportation future.

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, the largest electric utility in California, 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



	12/02	12/03	12/04	12/05	12/06	12/07
Edison International	100	185	281	393	421	504
S & P 500 Index	100	129	143	150	173	183
Philadelphia Utility Index	100	125	157	186	223	266
Dow Jones US Electricity	100	125	156	182	220	266

Note: Assumes $100 invested on December 31, 2002 in stock or index including reinvestment of dividends. Beginning this year, Edison International has selected the Philadelphia Utility Index as its peer group index. Performance of this index is regularly reviewed by management and the Board of Directors in understanding Edison International's relative performance, and is used in conjunction with elements of the company's incentive compensation programs. The prior benchmark, the Dow Jones US Electricity Index, is included for comparison purposes.

Table of Contents

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Glossary

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

AB	Assembly Bill
ACC	Arizona Corporation Commission
Ameren	Ameren Corporation
AFUDC	allowance for funds used during construction
APS	Arizona Public Service Company
ARO(s)	asset retirement obligation(s)
Brooklyn Navy Yard	Brooklyn Navy Yard Cogeneration Partners, L.P.
Btu	British Thermal units
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CARB	California Air Resources Board
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
DOJ	Department of Justice
DPV2	Devers-Palo Verde II
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.
EPAct 2005	Energy Policy Act of 2005
EPS	earnings per share
ERRA	energy resource recovery account
Exelon Generation	Exelon Generation Company LLC
FASB	Financial Accounting Standards Board
FPA	Federal Power Act
FERC	Federal Energy Regulatory Commission
FIN 39-1	Financial Accounting Standards Board Interpretation No. 39-1, Amendment of FASB Interpretation No. 39
FIN 46(R)	Financial Accounting Standards Board Interpretation No. 46, Consolidation of Variable Interest Entities

FIN 46(R)-6	Financial Accounting Standards Board Interpretation No. 46(R)-6, Determining Variability to be Considered in Applying FIN 46(R)
FIN 47	Financial Accounting Standards Board Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations
FIN 48	Financial Accounting Standards Board 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
FTRs	firm transmission rights
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
MISO	Midwest Independent Transmission System Operator
Mohave	Mohave Generating Station
Moody's	Moody's Investors Service
MRTU	Market Redesign Technical Upgrade
MW	megawatts
MWh	megawatt-hours
NAPP	Northern Appalachian
Ninth Circuit	United States Court of Appeals for the Ninth Circuit
NOV	notice of violation
NO_x	nitrogen oxide
NRC	Nuclear Regulatory Commission
NSR	New Source Review
NYISO	New York Independent System Operator
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

POD	Presiding Officer's Decision
PRB	Powder River Basin
PURPA	Public Utility Regulatory Policies Act of 1978
PX	California Power Exchange
QF(s)	qualifying facility(ies)
RGGI	Regional Greenhouse Gas Initiative
RICO	Racketeer Influenced and Corrupt Organization
ROE	return on equity
RPM	reliability pricing model
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. 141(R)	Statement of Financial Accounting Standards No. 141(R), Business Combinations
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
SFAS No. 159	Statement of Financial Accounting Standards No. 159. The Fair Value Option for Financial Assets and Financial Liabilities
SFAS No. 160	Statement of Financial Accounting Standards No. 160, Noncontrolling Interests in Consolidated Financial Statements
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 beyond those rates which may be adjusted from year to year by public utility regulators 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 laws and regulations, both at the state and federal levels, 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 cost and 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 to the extent not recovered through regulated rate cost escalation provisions or balancing accounts;
- 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 counterparty default in hedging transactions or power-purchase and 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;
- changes in the fair value of investments and other assets; and
- the risks inherent in the development of generation projects as well as transmission and distribution infrastructure replacement and expansion including those related to siting, financing, construction, permitting, and governmental approvals.

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, a rate-regulated electric utility, and EMG. EMG is the holding company for its principal wholly owned subsidiaries, 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.

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

This MD&A is presented in 13 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.

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

EDISON INTERNATIONAL

EDISON INTERNATIONAL: MANAGEMENT OVERVIEW

Edison International management engages in a comprehensive and rigorous strategic planning process for the company to continuously identify critical success factors, current trends and industry developments affecting the company on both a long-term and short basis. In addition, annually, senior management develops the Edison International goals for the upcoming year, based on this process. These goals are approved by the Edison International Board of Directors.

In 2008, Edison International has adopted the following goals as key to continued successful implementation of its strategic plan.

- Growth –
  - Achieve 2008 licensing and construction milestones for SCE's 2008 – 2012 capital investment plan.

    SCE expects to make capital investments up to $19 billion over the 2008 to 2012 period, subject to Board of Directors and other approvals, to meet system growth, ensure system reliability, replace and expand distribution and transmission infrastructure, construct and replace major components of generation assets and deploy EdisonSmartConnect[tm]. Portions of the capital investment plan remain subject to regulatory approvals. See "SCE: Liquidity — Capital Expenditures."
  - Execute 2008 milestones for EMG's diversified generation growth strategy and expand EMMT's business platform.

    EMG has undertaken a number of business development activities to continue to diversify its fuel type and expand its generation portfolio. See "EMG: Liquidity — Business Development."
  - Advance near- and longer-term low-emission generation technology strategies and projects.

    SCE and EMG have low-emission generation technology strategies and projects underway. See "SCE: Regulatory Matters — Current Regulatory Developments — Procurement of Renewable Resources," "EMG: Liquidity — Business Development," and "Other Developments — Environmental Matters."

- Operational Excellence –
  - Advance Edison International continuous improvement initiatives to drive efficient and cost-effective operations, and achieve 2008 milestones for SCE's Enterprise Resource Planning and EdisonSmartConnect[tm] programs, San Onofre Nuclear Generating Station business plan and energy efficiency action plan.

    Edison International has underway an enterprise wide project, called the Enterprise Resource Planning or ERP project, to implement a comprehensive, integrated software system from SAP to support the majority of its critical business processes during the next few years. EIX expects to implement SAP financial, supply chain, human resources and certain work management modules in 2008. See "Other Developments — Enterprise-Wide Software System Project." SCE plans to deploy state-of-the-art "smart" meters to its customers over a five-year period beginning in 2008. See "SCE: Other Developments — EdisonSmartConnect[tm]." In addition, SCE will work towards meeting its energy efficiency goals that were established by the CPUC in an Energy Efficiency Risk/Reward Incentive mechanism. See "SCE: Regulatory Matters — Current Regulatory Developments — Energy Efficiency Incentives."

- Environmental –
  - Achieve 2008 milestones to optimize value of capital expenditures for EMG environmental compliance.

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. EME expects that it will incur capital expenditures related to environmental compliance projects, mainly related to its coal plants. See "EMG: Liquidity — Capital Expenditures" and "Other Developments — Environmental Matters."

- Maintain and enhance leadership on environmental issues.

  Edison International is subject to numerous federal and state environmental laws and regulations, including those relating to SO_2 and NOx emissions, mercury emissions, ozone and fine particulate matter emissions, regional haze, water quality, and climate change. With respect to GHG emissions, Edison International will continue to work in support of fair GHG legislation and reporting and verification protocol as well as promoting fair renewable requirement standards imposed in California. See "Other Developments — Environmental Matters."

- Financial –
  - Achieve supportive regulatory decisions for the 2009 General Rate Case and the 2009 Cost of Capital Proceeding.

    SCE filed its GRC application on November 19, 2007 and expects a decision prior to year-end 2008. See "SCE: Regulatory Matters — Current Regulatory Developments — 2009 General Rate Case Proceeding." In addition, SCE expects the CPUC to issue a decision on Phase II of the cost of capital proceeding in April 2008. See "SCE: Regulatory Matters — Current Regulatory Developments — 2008 Cost of Capital Proceeding."

In addition to meeting our financial targets and the goals discussed above, Edison International's 2008 strategy also includes goals related to safety, operational targets, customer satisfaction, and people, values and culture, including enhancing the effectiveness of Edison International's ethics and compliance programs. Edison International's 2008 goals were developed consistent with its Leading the Way in Electricity values of integrity, excellence, respect, continuous improvement and teamwork.

2007

In 2007, Edison International continued effective execution of its strategic plan, with a focus on managed growth and operational excellence. Edison International met its 2007 goals associated with its strategic plan. Principal objectives achieved in 2007 are summarized below:

Managed Growth

- Achieve milestones for SCE's capital investment plan – In 2007, SCE invested more than $2.2 billion in its continued progress to replace and expand distribution and transmission infrastructure, construct and replace major components of generation assets, including the construction of four combustion turbine peaker plants to meet summer load demand, continued development of the advanced meter project, EdisonSmartConnect™, and replacement of the steam generators at San Onofre which is moving forward on schedule. SCE did receive a setback in the approval process of the Devers-Palo Verde II transmission line, which will be delayed for at least two years. See "SCE: Liquidity — Capital Expenditures" and "SCE: Regulatory Matters — Current Regulatory Developments — Peaker Plant Generation Projects" and "—EdisonSmartConnect™" and "—FERC Transmission Incentives" for further discussion of these matters.

- Diversifying the fuel type of EMG's generation assets – EME has expanded its business development activities in order to grow and diversify its existing portfolio of power projects, including renewable energy projects. Most of EME's near-term development and investment activity is in wind power. At December 31, 2007, EME had 566 MW of wind projects in service and another 447 MW of wind projects under construction, with scheduled completion dates during 2008. At December 31, 2007, EME had a development pipeline of potential wind projects with an estimated installed capacity of approximately

5,000 MW. The development pipeline represents potential projects with respect to which EME either owns the project rights or has exclusive acquisition rights. This development pipeline is supported by turbine purchase commitments of 1,166 MW for new wind projects. The majority of the turbines are scheduled to be delivered before the end of 2009. See "EMG: Liquidity and Capital Resources — Business Development" for details of activities during 2007.

Operational Excellence

- Achieve significant milestones for the Enterprise Resource Planning program – Edison International has continued progress on its ERP project. During 2007, EMG implemented SAP financial, procurement and material management and fuel management modules. SCE's progress continued on preparation for the implementation of SAP financial, supply chain, human resource and certain work management modules, expected to be implemented in 2008. See: "Other Developments — Enterprise-Wide Software System Project" for further discussion of this matter.
- SCE has continued to procure least-cost, best-fit power resources and execute effective hedging strategies consistent with the CPUC approved procurement plan – In 2007, SCE entered into contracts with new generation projects and reported full compliance with the Renewable Portfolio Standard goals for 2004, 2005, and 2006 and projects it will meet its renewable goals for 2007 and 2008 (see "SCE: Regulatory Matters — Current Regulatory Developments — Procurement of Renewable Resources"). The CPUC also found SCE's recorded fuel and energy expenses reasonable and SCE's contract administration, dispatch of generation resources and related spot market transactions compliant with SCE's CPUC-approved procurement plan from January 1, 2006 through December 31, 2006 and approved SCE's long-term procurement plan. In 2007, SCE took a leadership role in the development of near and long-term strategies to promote policies where SCE's bundled customers do not incur costs different than those of other load-serving entities.
- Optimizing the value of EMG's existing generation portfolio – During 2007 and January 2008, PJM completed capacity auctions under the PJM RPM for periods through May 31, 2011. EME participated in each auction, which sold forward significant capacity at prices from $40.80 per MW-day to $191.32 per MW-day. The increase in capacity prices determined through the PJM RPM reflects the auction design to encourage increased capacity resources to meet projected demand. As a result of these auctions, EME expects capacity revenue to increase significantly through May 31, 2011 as compared to the amounts realized by EME previously. For further discussion regarding the PJM and recent auctions, see "EMG: Market Risk Exposures — Commodity Price Risk — Capacity Price Risk."
- Environmental – In 2007, Edison International and its subsidiaries supported state-specific measures and participated in regional legislative initiatives to reduce GHG emissions and other environmental issues. We are advancing our leading environmental work in many areas, including energy efficiency and renewables. See "Other Developments — Environmental Matters" for further discussion.

Other significant developments in 2007 included:

- A CPUC decision that adopted an Energy Efficiency Risk/Reward Incentive mechanism covering at least two three-year periods (2006 – 2008 and 2009 – 2011). The intent of the mechanism is to elevate the importance of customer energy efficiency programs by allowing utility shareholders to participate in the benefits produced by the programs, ensuring that energy efficiency is viewed as a core part of the utilities' operations. See "SCE: Regulatory Matters — Current Regulatory Developments — Energy Efficiency Incentives" for further discussion.
- A FERC order which granted incentives for three of SCE's largest proposed transmission projects. The order grants a higher return on equity on SCE's transmission rate base in its next FERC transmission rate case and an additional increase for the Tehachapi, DPV2, and Rancho Vista projects, permits SCE to include in rate base 100% of prudently-incurred capital expenditures during the construction of all three

projects and 100% recovery of prudently-incurred abandoned plant costs for DPV2 and Tehachapi, if either or both of these projects are cancelled due to factors beyond SCE's control. See "SCE: Regulatory Matters — Current Regulatory Developments — FERC Transmission Incentives" for further discussion.

- During the past several years, the cost to build new generation has risen significantly. In September 2007, the Brattle Group prepared a report for the Edison Foundation (unaffiliated with Edison International) that identified four primary sources of the increase in construction costs: (1) material input costs, (2) shop and fabrication capacity, (3) cost of construction field labor, and (4) the market for large construction project management. SCE's major capital construction projects are approved by the CPUC and/or FERC and are expected to be included in ratebase for future recovery. Increases in EMG's costs can be partially mitigated to the extent that equipment has been procured as in the case of the wind turbines discussed above. However, for projects in development to be economically viable, higher capital costs will need to be reflected in higher power prices in power purchase agreements, or in higher forward prices for wholesale energy and capacity and/or renewable energy credits. The above factors may also increase the cost of constructing the environmental controls needed to reduce emissions. See "Other Developments — Environmental Matters — Air Quality Regulation — Clean Air Interstate Rule — Illinois" for a more detailed discussion.

- In May 2007, EME completed a private offering of $1.2 billion of its 7.00% senior notes due May 15, 2017, $800 million of its 7.20% senior notes due May 15, 2019 and $700 million of its 7.625% senior notes due May 15, 2027. EME used the net proceeds, together with cash on hand, to repay debt and make a dividend payment of $899 million to MEHC, the holding company of EME, which enabled MEHC to purchase substantially all of its 13.5% senior secured notes due 2008. In June 2007, MEHC redeemed in full its senior secured notes. In connection with the purchase of these notes, EMG recorded a total pre-tax loss of approximately $241 million (approximately $148 million after tax) on early extinguishment of debt in 2007.

- Edison International continued to strengthen its safety and ethics programs. Almost 98% of non-management employees completed ethics and compliance training in 2006 and 2007.

SOUTHERN CALIFORNIA EDISON COMPANY

SCE: LIQUIDITY

Overview

As of December 31, 2007, SCE had cash and equivalents of $252 million ($110 million of which was held by SCE's consolidated VIEs). As of December 31, 2007, long-term debt, including current maturities of long-term debt, was $5.08 billion. 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. At December 31, 2007, the credit facility supported $229 million in letters of credit and $500 million of short-term debt outstanding, leaving $1.77 billion available for liquidity purposes.

SCE's 2008 estimated cash outflows are expected to consist of:

- Projected capital expenditures of $2.8 billion primarily to replace and expand distribution and transmission infrastructure and construct and replace major components of generation assets (see "— Capital Expenditures" below);
- Dividend payments to SCE's parent company. The Board of Directors of SCE declared a $25 million dividend to Edison International which was paid in January 2008;
- 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 and power-procurement, through cash and equivalents on hand, operating cash flows and short-term borrowings. 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.

Due to recent market developments, there has been a significant reduction in market liquidity for auction rate bonds and interest rates on these bonds have risen. Consequently, in December 2007, SCE purchased in the secondary market $37 million of its auction rate bonds in December 2007 and $187 million in January and February 2008. The bonds remain outstanding and have not been retired or cancelled. SCE may remarket the bonds in a term rate mode in the first half of 2008 and terminate the insurance covering the bonds. See "SCE: Market Risk Exposures" for a further discussion.

In January 2008, SCE issued $600 million of 5.95% first and refunding mortgage bonds due in 2038. The proceeds were used to repay SCE's outstanding commercial paper of approximately $426 million and for general corporate purposes.

In January 2008, SCE repurchased 350,000 shares of 4.08% cumulative preferred stock at a price of $19.50 per share. SCE retired this preferred stock in January 2008 and recorded a $2 million gain on the cancellation of reacquired capital stock (reflected in the caption "Additional paid-in capital" on the consolidated balance sheets).

On February 13, 2008, President Bush signed the Economic Stimulus Act of 2008 (2008 Stimulus Act). The 2008 Stimulus Act includes a provision that provides accelerated bonus depreciation for certain capital expenditures incurred during 2008. Edison International expects that certain capital expenditures it incurs during 2008 will qualify for this accelerated bonus depreciation, which would provide additional cash flow benefits in 2008 and potentially 2009. Any cash flow benefits resulting from this accelerated depreciation should be timing in nature and therefore should result in a higher level of accumulated deferred income taxes reflected on Edison International's consolidated balance sheets, as well as its subsidiaries balance sheets. For

SCE, timing benefits related to deferred taxes should be incorporated into future ratemaking proceedings, impacting future period cash flow and rate base.

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. SCE's 2008 through 2012 capital investment plan which includes total capital spending of up to $19 billion is subject to approval by the Finance Committee of the Board of Directors. The 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 in SCE's 2009 GRC application. The 2012 planned expenditures are subject to future approval. Recovery of certain projects included in the 2008 through 2012 investment plan has been approved or will be requested through other CPUC-authorized mechanisms on a project-by-project basis. These projects include, among others, SCE's advanced metering infrastructure project, the San Onofre steam generator replacement project, and the peaker plant generation project. SCE plans total spending for 2008 through 2012 to be $1.2 billion, $450 million, and $58 million, for each project, respectively. Recovery of the 2008 through 2012 planned expenditures for FERC-jurisdictional projects will be requested in future transmission rate filings with the FERC. 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. During 2007, SCE spent $2.2 billion in capital expenditures related to its 2007 capital plan.

The estimated capital expenditures for the next five years are as follows: 2008 – $2.8 billion; 2009 – $3.9 billion; 2010 – $4.3 billion; 2011 – $4.4 billion; and 2012 – $3.6 billion.

Significant investments in 2008 are expected to include:

- $1.9 billion related to transmission and distribution projects;
- $313 million related to generation projects;
- $298 million related to information technology projects, including the implementation of the Enterprise Resource Planning project; and
- $277 million related to other customer service and shared services projects, including EdisonSmartConnect™.

Credit Ratings

At December 31, 2007, SCE's credit ratings were as follows:

	Moody's Rating	S&P Rating	Fitch Rating
Long-term senior secured debt	A2	A	A+
Short-term (commercial paper)	P-2	A-2	F-1

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

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, 2007, SCE's 13-month weighted-average common equity component of total capitalization was 50.59% resulting in the capacity to pay $308 million in additional dividends.

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, 2007, SCE's debt to total capitalization ratio was 0.44 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, 2007, SCE had a net deposit of $266 million (consisting of $37 million in cash and reflected in "Margin and collateral deposits" on the consolidated balance sheets and $229 million in letters of credit) with counterparties and other brokers. Cash deposits with brokers and counterparties earn interest at various rates.

Future cash collateral requirements may be higher than the margin and collateral requirements at December 31, 2007, if wholesale energy prices increase or the amount hedged increases. SCE estimates that margin and collateral requirements for energy contracts outstanding as of December 31, 2007, could increase by approximately $421 million over the remaining life of the contracts using a 95% confidence level.

The credit risk exposure from counterparties for power and gas trading activities are measured as the difference between the contract price and current fair value of open positions. SCE enters into master agreements which typically provide for a right of setoff. Accordingly, SCE's credit risk exposure from counterparties is based on a net exposure under these arrangements. At December 31, 2007, the amount of exposure as described above, broken down by the credit ratings of SCE's counterparties, was as follows:

In millions	December 31, 2007
S&P Credit Rating	
A or higher	**$ 71**
A-	**30**
BBB+	**15**
BBB	**—**
BBB-	**—**
Below investment grade	**258**
Total	**$ 374**

SCE has structured transactions (tolling contracts) in which SCE purchases all of the output of a plant from the counterparty. Accordingly, a default by a counterparty under a structured transaction, including a default as a result of a bankruptcy, would likely have a material adverse effect on SCE. In addition, SCE's structured transactions may be for multiple years which increases the volatility of the fair value position of the transaction. A number of the counterparties with which SCE has structured transactions do not currently have an investment grade rating or are below investment grade. SCE seeks to mitigate this risk through diversification of its structured transactions, when available. Despite this, there can be no assurance that these efforts will be successful in mitigating credit risk from contracts.

SCE requires that counterparties with below investment grade ratings or those that do not currently have an investment grade rating post collateral. In the event of default by the counterparty, SCE would be able to use that collateral to pay for the commodity purchased or to pay the associated obligation in the event of default by the counterparty. Furthermore, all of the contracts that SCE has entered into with counterparties are entered into under SCE's short-term and long-term procurement plan which has been approved by the CPUC. As a result, SCE would qualify for regulatory recovery for any defaults by counterparties on these transactions. In addition, SCE subscribes to rating agencies and various news services in order to closely monitor any changes that may affect the counterparties' ability to perform.

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 could 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. 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.

SCE expects to continue its current administrative role associated with the CDWR contracts in the MRTU market and will continue to act as an agent for these transactions.

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 was a current property right created by the restructuring legislation and a financing order of the CPUC and consisted generally of the right to be paid a specified amount from nonbypassable rates charged to residential and small commercial customers. The rate reduction notes were repaid over 10 years, with the final principal payment made in December 2007, through these nonbypassable residential and small commercial customer rates, which constitute the transition property purchased by SCE Funding LLC. The nonbypassable rates being charged to customers are expected to cease at the time of SCE's next consolidated rate change which is expected to be in March 2008. All amounts collected subsequent to the final principal payment made in December 2007 will be refunded to ratepayers. 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 were shown as long-term debt in the consolidated financial statements, SCE Funding LLC is legally separate from SCE. As a result of the payment of the bonds, SCE Funding LLC terminated its registration on December 27, 2007 and is no longer required to file reports with the U.S. Securities and Exchange Commission.

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 which is made up of the carrying cost on capital investment (depreciation, return and taxes), plus the authorized level of operation and maintenance expense. The return is established by multiplying an authorized rate of return, determined in annual cost of capital proceedings (as discussed below), by rate base. 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 — 2009 General Rate Case Proceeding" for SCE's current annual revenue requirement.

Adopted operation and maintenance costs include approval for cost inflation assumptions for principal operating costs such as labor and benefits. During the GRC cycle, cost inflation assumptions are updated by SCE, subject to CPUC approval, which mitigates the potential impact of cost inflation being materially different from the authorized levels.

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. 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 2007, 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. SCE's authorized return on common equity is 11.5% for 2008. See " — Current Regulatory Developments — 2008 Cost of Capital Proceeding" for a discussion of SCE's 2008 cost of capital proceeding.

Cost-Recovery Rates

Revenue requirements to recover SCE's costs of fuel, purchased power, demand-side management programs, nuclear decommissioning, 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.

Energy Efficiency Shareholder Risk/Reward Incentive Mechanism

On September 20, 2007, the CPUC issued a decision that adopted an Energy Efficiency Risk/Reward Incentive mechanism covering at least two three-year periods (2006 – 2008 and 2009 – 2011). On January 31, 2008, the CPUC issued a decision which made clarifying modifications to the adopted mechanism. The mechanism allows for both incentives and economic penalties based on SCE's performance toward meeting CPUC goals for energy efficiency. The intent of the mechanism is to elevate the importance of customer energy efficiency programs by allowing utility shareholders to participate in the benefits/penalties produced by such programs, ensuring that energy efficiency is viewed as a core part of the utilities' operations. Both incentives and economic penalties for each three year period are capped at $200 million. See "SCE: Regulatory Matters — Energy Efficiency Shareholder Risk/Reward Incentive Mechanism" for further discussion of SCE's 2006 – 2008 program cycle.

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 $2.3 billion was collected in 2007) 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. On January 1, 2007, SCE's bundled service system average rate was 14.5¢ per-kWh (including 3.1¢ per-kWh related to CDWR which is not recognized as revenue by SCE). On February 14, 2007, SCE's system average rate decreased to 13.9¢ per-kWh (including 3.0¢ per-kWh related to CDWR) mainly as the result of projected lower natural gas prices in 2007, as well as the refund of overcollections in the ERRA balancing account that occurred in 2006 from lower than expected natural gas prices and higher than expected sales in the summer of 2006. In addition, the rate change incorporates the redesign of SCE's tiered rate structure and collection of the residential rate increase deferral. In connection with the February 14, 2007, system average rate change, the residential rates in the top two tiers were decreased. The residential rates at the lower tiers are capped due to AB 1X discussed below.

During the 2001 energy crisis, the California Legislature passed AB 1X which capped the rates for low-use residential customers. AB 1X fixes the rates for almost half of SCE's residential customers. As a result, any residential revenue requirement increase is allocated to the remaining residential customers. This causes wide variation in the average rates SCE's residential customers pay. This rate inequity is causing increasingly high bills for a subset of SCE's customers, especially following major summer heat storms. SCE is currently working with the CPUC, consumer groups, and key California public officials to seek support for a means to mitigate the effects of AB 1X.

On November 27, 2007, SCE revised its 2008 ERRA forecast application, forecasting an ERRA revenue requirement of $4.03 billion, which represents an increase of $281 million over SCE's adopted 2007 ERRA revenue requirement. In addition, SCE requested to consolidate other rate changes authorized by the CPUC with this ERRA revenue requirement increase to be effective by the end of February 2008. After taking into account all other revenue requirement changes, SCE estimates that the system average rate for bundled service customers will decrease by 0.2¢ per-kWh in 2008. The bundled service system average rate will be 13.7¢ per-kWh in 2008 (including a slightly lower 2.9¢ per-kWh related to CDWR which is lower than that in effect in third quarter of 2007).

Current Regulatory Developments

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

2009 General Rate Case Proceeding

SCE filed its GRC application on November 19, 2007. The application requests a 2009 base rate revenue requirement of $5.199 billion, an increase of approximately $858 million over the projected authorized base rate revenue requirements. After considering the effects of sales growth and other offsets, SCE's request would be a $726 million increase over current authorized base rate revenue. If the CPUC approves these requested increases and allocates them to ratepayer groups on a system average percentage change basis, the percentage increases over current base rates and total rates are estimated to be 16.2% and 6.2%, respectively. The requested revenue requirement increase is necessary for SCE to build facilities to serve new customers, reinforce its system to accommodate customer load growth, replace aging infrastructure, meet regulatory requirements in generation and electricity procurement, fund increased operations and maintenance costs, and provide for increased costs to recruit, train, and retain employees in light of anticipated retirements. SCE's application also proposes a post-test year ratemaking mechanism which would result in 2010 and 2011 base rate revenue requirement increases, net of sales growth, of $216 million and $287 million, respectively, for the same reasons. SCE also requested in its application that Mountainview be included in utility rate base and its operating costs be recovered through the 2009 GRC revenue requirement rather than the current structure under which SCE recovers Mountainview generating costs through a power purchase agreement with no significant impact on rates. Several parties filed protests in December 2007, addressing various aspects of SCE's application. On February 7, 2008, a Scoping Memo was issued, which included the formal schedule and scope of issues to be addressed in the GRC. SCE cannot predict the revenue requirement the CPUC will ultimately authorize or precisely when a final decision will be adopted although a final decision is expected prior to year-end.

2008 Cost of Capital Proceeding

On December 21, 2007, the CPUC granted SCE's requested rate-making capital structure of 43% long-term debt, 9% preferred equity and 48% common equity for 2008. The CPUC also authorized SCE's 2008 cost of long-term debt of 6.22%, cost of preferred equity of 6.01% and a return on common equity of 11.5%. The impact of this Phase I decision resulted in a $7 million decrease in SCE's annual revenue requirement. In Phase II of the proceeding, the CPUC is considering whether to replace the current annual cost of capital application with a multi-year mechanism. The CPUC expects to issue a decision on Phase II in April 2008.

Energy Efficiency Shareholder Risk/Reward Incentive Mechanism

On September 20, 2007, the CPUC issued a decision that adopted an Energy Efficiency Risk/Reward Incentive mechanism with subsequent modifications issued on January 31, 2008. Under this mechanism SCE has the opportunity to earn an incentive of 9% of the value of the total energy efficiency savings if it achieves between 85% and 100% of its energy efficiency goals for the cumulative three year period and can earn 12% of the value of the energy efficiency savings if 100% or greater of its goals are achieved. Economic penalties would be imposed in the event the utility achieves 65% or less of its goals. The mechanism also establishes a deadband between 65% and 85% of energy efficiency goals, where no economic penalty or incentive would be earned. The mechanism allows for collection of 65% of the first two years' (2006 – 2007) progress towards goals beginning in 2009; 65% of the next year's (2008) progress in 2010 and collection of a final true-up payment for the remaining 35%, as adjusted for actual performance in 2011. The January 2008 modifications allow the utilities to retain the first and second progress payments as long as the utilities meet a minimum of 65% of the goals, as measured by the CPUC in the third and final payment. If the utilities fall below the 65% level, the progress payment would need to be refunded and economic penalties would be incurred. Each progress payment is independently calculated based on performance to date and SCE may earn at either the 9% or 12% incentive level for each progress payment. SCE is scheduled to file advice filings in September of each year requesting recovery of the progress payments in accordance with the mechanism. SCE expects it will recognize earnings in the amount of the progress payments upon CPUC acceptance of its filing, expected in the fourth quarter of each year. SCE would record penalties at any time that it is probable that it will not meet 65% of the goals. Assuming SCE achieves all of its energy efficiency goals, and delivers customer benefits of approximately $1.2 billion, the three-year earnings opportunity for the 2006 – 2008 period would be approximately $146 million pre-tax. The January 2008 modifications incorporate an update to the effective useful life of the energy efficiency measures installed. If the draft CPUC effective useful life study is adopted in its current form, the effective useful life of residential compact fluorescent lights, one of the largest contributors to SCE's energy efficiency portfolio, would be reduced and SCE's earnings opportunity would decrease to approximately $124 million. Timing of progress payment claims is linked to the completion of CPUC reports. Delays in CPUC reports could cause delays in recognizing earnings for these claims. Under this mechanism, SCE is scheduled to file for expected benefits for the 2006 and 2007 timeframe in September 2008. There is no assurance of earnings in any given year. If approved by the CPUC, SCE currently projects, based on preliminary results, that it will record a progress payment in the range of $41 million to $49 million in the fourth quarter of 2008 for the first two years (2006 – 2007) of the program cycle. The final amount of the progress payment will be based on a CPUC report, scheduled to be complete in August 2008 and utilized in the September filing. SCE expects to collect this progress payment in rates in 2009. SCE estimates that it will meet 100% of its energy efficiency goals for the entire program period. In the event SCE reaches 65% or less of its goals for the 2006 – 2008 period, the approximate economic penalty could range between $58 million to $200 million for the three year period, depending on SCE's performance against its energy efficiency goals. The CPUC will review the operation of the mechanism over two three-year program periods (2006 – 2008 and 2009 – 2011) to determine if any modifications to the mechanism are warranted for the 2012 – 2014 program period.

FERC Transmission Incentives

On November 16, 2007, the FERC issued an order granting incentives on three of SCE's largest proposed transmission projects:

- A 125 basis point ROE adder on SCE's future proposed base ROE ("ROE Adder") for Devers-Palo Verde II ("DPV2"), which is a high voltage (500 kV) transmission line from the Valley substation to the Devers substation near Palm Springs, California to a new substation near Palo Verde, west of Phoenix, Arizona;
- A 125 basis point ROE Adder for the Tehachapi Transmission Project ("Tehachapi"), which is an eleven segment project consisting of newly-constructed and upgraded transmission lines and associated substations to interconnect renewable generation projects near the Tehachapi and Big Creek area; and
- A 75 basis point ROE Adder for the Rancho Vista Substation Project ("Rancho Vista"), which is a new 500 kV substation in the City of Rancho Cucamonga.

The order also grants a higher return on equity on SCE's entire transmission rate base in SCE's next FERC transmission rate case for SCE's participation in the CAISO. SCE has not yet determined when it expects to file its next FERC rate case. In addition, the order permits SCE to include in rate base 100% of prudently-incurred capital expenditures during construction, also known as CWIP, of all three projects and 100% recovery of prudently-incurred abandoned plant costs for DPV2 and Tehachapi, if either or both of these projects are cancelled due to factors beyond SCE's control.

The Tehachapi and Rancho Vista projects are proceeding as anticipated. However, despite SCE having obtained approvals for the DPV2 project from the CPUC and other Arizona governmental agencies, by a decision dated June 6, 2007 the Arizona Corporation Commission (ACC) denied approval of the DPV2 project. SCE filed an appeal of the ACC's decision with the Maricopa County Superior Court on August 31, 2007 and agreed to a stay of the appeal until March 2008 in order to allow it to explore potential options with the Arizona stakeholders, including the ACC. SCE continues to evaluate its options, which include but are not limited to, filing a new application with the ACC and building the project in various phases. The ACC denial has resulted in a minimum two-year delay of the DPV2 project. For the period January 2003 to December 31, 2007, SCE has spent approximately $31 million on this project. SCE expects to fully recover its costs from this project, but cannot predict the outcome of regulatory proceedings.

FERC Construction Work in Progress Mechanism

On December 21, 2007, SCE filed a revision to its Transmission Owner Tariff to collect 100% of CWIP in rate base for Tehachapi, DPV2, and Rancho Vista, as authorized by FERC in its transmission incentives order discussed above. In the CWIP filing, SCE proposed a single-issue rate adjustment ($45 million or a 14.4% increase) to SCE's currently authorized base transmission revenue requirement to be made effective on March 1, 2008 and later adjusted for amounts actually spent in 2008 through a new balancing account mechanism. The rate adjustment represents actual expenditures from September 1, 2005 through November 30, 2007, projected expenditures from December 1, 2007 through December 31, 2008, and a return on equity (which includes the return on equity adders approved for Tehachapi, DPV2 and Rancho Vista). SCE projects that it will spend a total of approximately $244 million, $27 million, and $181 million for Tehachapi, DPV2, and Rancho Vista, respectively, from September 1, 2005 through the end of 2008. The 2008 DPV2 expenditure forecast is limited to projected consulting and legal costs associated with SCE's continued efforts to obtain regulatory approvals necessary to construct the DPV2 Project. If the CWIP filing is approved, the resulting incremental CWIP revenue requirement will be added to the existing base transmission revenue requirement. FERC is expected to issue a decision on the CWIP filing by February 29, 2008.

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 (base generation and procurement costs), 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.

At December 31, 2007, the ERRA was overcollected by $433 million, which was 6.32% of SCE's prior year's generation revenue. On November 27, 2007, SCE notified the CPUC that the 2007 ERRA overcollection exceeded 5% of SCE's generation revenue from the prior year and proposed to include the refund of the ERRA over-collection in the planned consolidated rate change on January 1, 2008 or soon thereafter. As discussed above in "— Impact of Regulatory Matters on Customer Rates," SCE expects a final CPUC decision in mid-March and will begin to refund the over-collection to customers in early April 2008.

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 (known as the month-ahead system resource adequacy showing). For years after 2006, SCE is required to make its year-ahead system resource adequacy showing (90% threshold) in the fall of the calendar year prior to the compliance year. SCE made a showing of compliance with its system resource adequacy requirements in each of its monthly compliance filings for each month in 2007. SCE made a showing of compliance with its year-ahead system resource adequacy requirements for 2007 and 2008 in November 2006 and October 2007, respectively. SCE expects to make a showing of compliance with its system resource adequacy requirements in each of its month-ahead system resource adequacy compliance filings for 2008. The system resource adequacy requirements provide for penalties of 300% of the cost of new monthly capacity for failing to meet the system resource adequacy requirements.

Under the local resource adequacy requirements, SCE must demonstrate on an annual basis 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. SCE made a showing of compliance with its local resource adequacy requirements for 2007 and 2008 in November 2006 and October 2007, respectively.

The resource adequacy compliance filings are subject to approval by the CPUC. SCE expects to be in full compliance and does not expect to incur any resource adequacy program penalties.

Peaker Plant Generation Projects

In August 2006, the CPUC issued a ruling addressing electric reliability needs in Southern California for summer 2007 that directed SCE, among other things, to pursue new utility owned peaker generation that would be online by August 2007. In response, SCE pursued construction of five combustion turbine peaker plants. In August 2007, four of these peaker plants were placed online and all four units have been dispatched to help meet peak customer demands and other system requirements. SCE continues to pursue the construction of the fifth project, but the required development permit has been denied by the City of Oxnard. SCE has appealed this denial to the Coastal Commission and expects a decision in the first half of 2008. SCE cannot predict the outcome of the proceeding nor estimate the impact of a delayed permit issuance on the project's construction schedule. In December 2007, pursuant to the CPUC's August 2006 ruling, SCE filed an application with the CPUC for recovery of $238 million of capital costs of acquiring and installing the four installed peakers recorded as of November 30, 2007, and projecting $24 million of additional construction-related capital expenditures. SCE proposes recovery of the latter amount through SCE's 2009 ERRA proceeding. Although the fifth peaker has not yet been permitted and installed it has been largely engineered and fabricated and as of December 31, 2007, SCE has incurred capital costs of approximately $36 million for that peaker. In the application SCE proposes to continue tracking the capital costs of the fifth peaker according to the interim cost tracking mechanism that was previously approved by the CPUC for all five peaker projects while they were in construction, and SCE proposes to file a separate cost recovery application for the fifth peaker after it is installed or its final disposition is otherwise determined. SCE believes it will be able to site the fifth peaker at another location, sell the peaker, or utilize it for spare parts if there is an unfavorable permitting outcome. SCE expects to fully recover its costs from these projects, but cannot predict the outcome of regulatory proceedings. SCE expects a CPUC decision on its December 2007 application in the second half of 2008.

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.

In March 2007, SCE successfully challenged the CPUC's calculation of SCE's annual targets. This change is expected to enable SCE to meet its target for 2007. On April 3, 2007, SCE filed its renewable portfolio standard compliance report for 2004 through 2006. The compliance report confirms that SCE met its renewable goals for each of these years. In light of the annual target revisions that resulted from the March 2007 successful challenge to the CPUC's calculation, the report also projects that SCE will meet its renewable goals for 2007 and 2008 but could have a potential deficit in 2009. The potential deficit in 2009, however, does not take into account future procurement opportunities or the full utilization by SCE of the CPUC's rules for flexible compliance with annual targets. It is unlikely that SCE will have 20% of its annual electricity sales procured from renewable resources by 2010. However, SCE may still meet the 20% target by utilizing the flexible compliance rules.

SCE is scheduled to update the compliance report discussed above in March 2008, and currently anticipates demonstrating full compliance for the procurement year 2007 as well as forecasting full compliance, with the use of flexible compliance rules, for the procurement year 2008. SCE continues to engage in several renewable procurement activities including formal solicitations approved by the CPUC, bilateral negotiations with individual projects and other initiatives.

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.

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. The other Mohave co-owners subsequently made similar announcements. 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, decommissioning and apportionment of the land among the owners, or developing renewable energy production.

Following the suspension of Mohave operations at the end of 2005, the plant's workforce was reduced from over 300 employees to 37 employees by the end of 2007. SCE recorded $5 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, 2007, SCE had a Mohave net regulatory asset of approximately $68 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.

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. On March 29, 2007, the FERC issued an order agreeing with SCE's position that the charges incurred by the ISO were related to voltage support and should be allocated to the scheduling coordinators, rather than to SCE as a transmission owner. The Cities filed a request for rehearing of the FERC's order on April 27, 2007. On May 25, 2007, the FERC issued a procedural order granting the rehearing application for the limited purpose of allowing the FERC to give it further consideration. In a future order, FERC may deny the rehearing request or grant the requested relief in whole or in part. SCE believes that the most recent substantive FERC order correctly allocates responsibility for these ISO charges. However, SCE cannot predict the final outcome of the rehearing. If a subsequent regulatory decision changes the allocation of responsibility for these charges, and SCE is required to pay these charges as a transmission owner, SCE may seek recovery in its reliability service rates. SCE cannot predict whether recovery of these charges in its reliability service rates would be permitted.

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 and line loss charges incurred by SCE on the DWP's behalf. The scheduling coordinator charges had been billed to the DWP under a FERC tariff that was 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.

In January 2008, an agreement between SCE and the DWP was executed settling the dispute discussed above. The settlement had been previously approved by the FERC in July 2007. The settlement agreement provides that the DWP will be responsible for line losses and SCE would be responsible for the scheduling coordinator charges. During the fourth quarter of 2007, SCE reversed and recognized in earnings (under the caption "Purchased power" in the consolidated statements of income) $30 million of an accrued liability representing line losses previously collected from the DWP that were subject to refund. As of December 31, 2007, SCE had an accrued liability of approximately $22 million (including $3 million of interest) representing the estimated amount SCE will refund for scheduling coordinator charges previously collected from the DWP. SCE made its first refund payment on February 20, 2008 and the second refund payment is due on March 15, 2008. SCE previously received FERC-approval to recover the scheduling coordinator charges from all transmission grid customers through SCE's transmission rates and on December 11, 2007 the FERC accepted SCE's proposed transmission rates reflecting the forecast levels of costs associated with the settlement. Upon signing of the agreement in January 2008, SCE recorded a regulatory asset and recognized in earnings the amount of scheduling coordinator charges to be collected through rates.

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.

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.

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, in late 2005, the Ninth Circuit ruled in Bonneville Power Admin v. FERC 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 or refunds against the governmental power sellers.

In March 2007, SCE, PG&E and the Oversight Board filed claims in the U.S. Court of Federal Claims against two federal agencies that sold power into California during the energy crisis. On February 7, 2008, the federal agencies filed a motion to dismiss the case. The Court's ruling on the motion is expected in the second half of 2008. In April 2007, SCE, along with PG&E, the Oversight Board and SDG&E, filed claims for refunds against several non-federal governmental power sellers in the Los Angeles Superior Court.

In October 2007, the FERC issued an order on remand from the Ninth Circuit's Bonneville decision, in which it concluded that the decision required the FERC to vacate its previous orders compelling governmental sellers during the California energy crisis to pay refunds. Based on this conclusion, the FERC also ordered the release of the amounts that had been withheld from governmental sellers as well as any collateral posted by the sellers for power delivered by them during the energy crisis. In its order, the FERC also expressly recognized that civil lawsuits against the governmental sellers could provide an alternative refund remedy for SCE and the other California utilities. It also left open the possibility that a court could order the ISO or PX to retain collateral. SCE cannot predict at this time the ultimate impact of the FERC's orders on SCE's ability to recover refunds from governmental power sellers through the pending lawsuits.

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 2006 and 2007, SCE received distributions of approximately $55 million and $24 million, respectively, on its allowed bankruptcy claim. Additional distributions are expected but SCE cannot currently predict the amount or timing of such distributions.

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 for the years 1997 – 2003. SCE received $8 million in reliability incentive awards for the period 1997 – 2000 and applied for a reward of $5 million for 2001. For 2002, SCE's data indicated that it earned no reward and incurred no penalty. For 2003, based on the application of the PBR mechanism, it would incur a penalty of $3 million and accrued a charge for that amount in 2004. On February 28, 2005, SCE provided its final investigation report to the CPUC concluding that the reliability reporting system was 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. 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 DRA and The Utility Reform Network, filed testimony on these matters recommending various refunds and penalties be imposed on SCE. In their testimony, the various parties made refund and penalty recommendations that range up to the following amounts: refund or forgo $48 million in rewards for customer satisfaction, impose $70 million penalties for customer satisfaction, refund or forgo $35 million in rewards for employee safety, impose $35 million penalties for employee safety, impose $102 million in statutory penalties, refund $84 million related to amounts collected in rates for employee bonuses ("results sharing"), refund $4 million of miscellaneous survey expenses, and require $10 million of new employee safety programs. These recommendations total up to $388 million. On October 16, 2006, SCE filed testimony opposing the various refund and penalty recommendations of the CPSD and other intervenors.

On October 1, 2007, a POD was released ordering SCE to refund $136 million, before interest, and pay a statutory penalty of $40 million. Included in the amount to be refunded are $28 million related to customer satisfaction rewards, $20 million related to employee safety rewards, and $77 million related to results sharing. The decision requires that the proposed results sharing refund of $77 million (based on year 2000 data) be adjusted for attrition and escalation which increases the results sharing refund to $88 million. Interest as of December 31, 2007, based on amounts collected for customer satisfaction, employee safety incentives and results sharing, including escalation and attrition adjustments, would add an additional $28 million to this amount. The POD also requires SCE to forgo $35 million in rewards for which it would have otherwise been eligible. Included in the amount to be forgone is $20 million related to customer satisfaction rewards and $15 million related to employee safety rewards.

On October 31, 2007, SCE appealed the POD to the CPUC. The CPSD and an intervenor also filed appeals. The CPSD appeal requested that: (1) the statutory penalty be increased from $40 million to $83 million (2) a penalty be imposed under the PBR customer satisfaction and employee safety mechanisms in the amount of $48 million and $35 million, respectively, and (3) SCE refund/forgo rewards earned under the customer satisfaction and employee safety mechanisms of $48 million and $35 million, respectively. The appealing intervenor asked that the statutory penalty be increased to as much as $102 million. Oral argument on the appeals took place on January 30, 2008, and it is uncertain when the CPUC will issue a decision.

SCE cannot predict the outcome of the appeal. Based on SCE's proposed refunds, the combined recommendations of the CPSD and other intervenors, as well as the POD, 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 (approximately $16 million as of December 31, 2007) on collected amounts.

The system reliability component of PBR was not addressed in the POD. Pursuant to an earlier order in the case, system reliability incentives will be addressed in a second phase of the proceeding, which commenced with the filing of SCE's opening testimony in September 2007. In that testimony, SCE confirmed that its PBR system reliability results, which reflected rewards of $13 million for 1997 through 2002 and a penalty of $3 million in 2003 were valid. An indefinite suspension of the schedule for the second phase of the proceeding pending resolution of the appeals of the POD has been granted. SCE cannot predict the outcome of the second phase.

Market Redesign Technical Upgrade

In early 2006, the ISO began a program to redesign and upgrade the wholesale energy market across ISO's controlled grid, known as the MRTU. The programs under the MRTU initiative are designed to implement market improvements to assure grid reliability, more efficient and cost-effective use of resources, and to create technology upgrades that would strengthen the entire ISO computer system. The redesigned California energy market under the MRTU is expected to include the following new features, among others, which are not part of the current ISO real-time only market:

- An integrated forward market for energy, ancillary services and congestion management that operates on a day-ahead basis;
- Congestion management that represents all network transmission constraints;
- CRRs to allow market participants to manage their costs of transmission congestion (see "SCE: Market Risk Exposures — Commodity Price Risk" for further discussion);
- Local energy prices by price nodes (approximately 3,000 nodes in total), also known as locational marginal pricing; and
- New market rules and penalties to prevent gaming and illegal manipulation of the market as well as modifications to certain existing market rules.

The MRTU was scheduled for implementation on March 31, 2008 and has been delayed to the fall of 2008. No new implementation date has been announced. Power will be scheduled on a nodal basis, rather than the current zonal system, which will aid in grid reliability and congestion management. Furthermore, the MRTU will incorporate the CPUC's resource adequacy requirements to ensure that there are adequate energy resources in critical areas. The MRTU will not affect how costs are recovered through rates. SCE continues to work with the ISO to develop the MRTU.

SCE: OTHER DEVELOPMENTS

EdisonSmartConnect^{tm}

SCE's EdisonSmartConnect^{tm} project involves installing state-of-the-art "smart" meters in approximately 5.3 million households and small businesses through its service territory. The development of this advanced metering infrastructure is expected to be accomplished in three phases: the initial design phase to develop the new generation of advanced metering systems (Phase I), which was completed in 2006; the pre-deployment phase (Phase II) to field test and select EdisonSmartConnect^{tm} technologies, select the deployment vendor and finalize the EdisonSmartConnect^{tm} business case for full deployment, which was conducted during 2007; and the final deployment phase (Phase III), to deploy meters to all residential and small business customers under 200 kW over a five-year period which is expected to begin in 2008 and be completed in 2012. The total cost for this project, including Phase II pre-deployment, is estimated to be $1.7 billion of which $1.25 billion is estimated to be capitalized and included in utility rate base. The remaining book value for SCE's existing meters at December 31, 2007 is $407 million. SCE expects to recover the remaining book value of the existing meters over their remaining lives through its 2009 GRC application.

On July 26, 2007, the CPUC approved $45 million for Phase II of this project. The Phase II work was completed in December 2007. SCE filed its Phase III application on July 31, 2007, requesting CPUC authorization to deploy EdisonSmartConnect[tm] meters. SCE expects a decision on the Phase III application by August 2008.

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 March 2001, the Hopi Tribe was permitted to intervene as an additional plaintiff.

In April 2004, the District Court denied 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. In September 2007, the Federal Circuit reversed a lower court decision on remand in the related lawsuit, finding that the U.S. Government had breached its trust obligation in connection with the setting of the royalty rate for the coal supplied to Mohave. Subsequently, the Federal Circuit denied the U.S. Government's petition for rehearing. The U.S. Government may, however, still seek review by the Supreme Court of the Federal Circuit's September decision.

Pursuant to a joint request of the parties, the District Court granted a stay of the action in October 2004 to allow the parties to attempt to negotiate a resolution of the issues associated with Mohave with the assistance of a facilitator. In a joint status report filed on November 9, 2007, the parties informed the court that their mediation efforts had terminated and subsequently filed a joint motion to lift the stay. The parties have also filed recommendations for a scheduling order to govern the anticipated resumption of litigation. The Court has not yet ruled on either the motion to lift the stay or the scheduling recommendations, but has scheduled a status hearing for March 6, 2008. SCE cannot predict the outcome of the Navajo Nation's and Hopi Tribe's complaints against SCE or the ultimate impact on these complaints of the Supreme Court's 2003 decision and the on-going litigation by the Navajo Nation against the U.S. Government in the related case.

Palo Verde Nuclear Generating Station Inspection

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 reduction in the ability to cool water before returning it to the plant. The second inspection identified five violations, but none of those resulted in increased NRC scrutiny. The third 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 based on the outcome of completed surveys of its plant personnel and self-assessments of its programs and procedures. These corrective actions are currently being developed in conjunction with the NRC, and are forecast to be completed and embodied in an NRC Confirmatory Order by the end of February 2008. These corrective actions will increase costs to both Palo Verde and its co-owners, including SCE. SCE cannot calculate the total increase in costs until the corrective actions are finalized and the NRC issues the Confirmatory Order. The operation and maintenance costs (including overhead) increased in 2007 by approximately $7 million from 2006. SCE presently estimates that operation and maintenance costs will increase by approximately $23 million (nominal) over the two year period 2008 – 2009, from 2007 recorded costs including overhead costs. SCE also is unable to estimate how long SCE will continue to incur these costs.

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 $46 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 was filed on February 22, 2008, 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 and some of Unit 2's spent fuel is stored. SCE, as operating agent, plans to transfer fuel from the Unit 2 and 3 spent fuel pools to the independent storage installation on an as-needed basis to maintain full core off-load capability for Units 2 and 3. There are now sufficient dry casks and modules available at the independent spent fuel storage installation to meet plant requirements through 2008. SCE plans to add storage capacity incrementally to meet the plant requirements 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 add storage capacity incrementally 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 (11.5% for 2008 and 11.6% for 2007 and 2006), 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, 2007, SCE did not believe that its short-term debt was subject to interest rate risk, due to the fair market value being approximately equal to the carrying value.

At December 31, 2007, the fair market value of SCE's long-term debt was $5.10 billion, compared to a carrying value of $5.08 billion. A 10% increase in market interest rates would have resulted in a $287 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 $318 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 mitigate 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 enters into energy options, tolling arrangements, and forward physical contracts. In the first quarter of 2007 SCE secured FTRs through the annual ISO auction. These FTRs provide SCE with scheduling priority in certain transmission grid congestion areas in the day-ahead market and qualify as derivative instruments. SCE also 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.

SCE records its derivative instruments on its consolidated balance sheets at fair value unless they meet the definition of a normal purchase or sale. Certain derivative instruments do not meet the normal purchases and sales exception because demand variations and CPUC mandated resource adequacy requirements may result in physical delivery of excess energy that may not be in quantities that are expected to be used over a reasonable period in the normal course of business and may then be resold into the market. In addition, certain contracts do not meet the definition of clearly and closely related under SFAS No. 133 since pricing for certain renewable contracts is based on an unrelated commodity. 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 – net; therefore, fair value changes do not affect earnings. Hedge accounting is not used for these transactions due to this regulatory accounting treatment.

In September 2007, the ISO allocated CRRs to SCE which will entitle SCE to receive (or pay) the value of transmission congestion at specific locations. These rights will act as an economic hedge against transmission congestion costs in the MRTU environment which was expected to be operational March 31, 2008 and has been delayed to the fall of 2008. The CRRs meet the definition of a derivative under SFAS No. 133. As of December 31, 2007 there were no quoted long-term market prices for the CRRs allocated to SCE. Although an auction was held in December 2007, the auction results did not provide sufficient evidence of long-term market prices. As a result of the insufficient market pricing evidence and the uncertainty of when the MRTU will become operational, SCE is unable to reasonably assess the fair value of the allocated CRRs as of December 31, 2007.

Any future fair value changes, given a MRTU market, will be recorded in purchased-power expense and offset through the provision for regulatory adjustments 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 are not expected to affect earnings.

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, 2007		December 31, 2006	
In millions	Assets	Liabilities	Assets	Liabilities
Energy options	$ —	$ 43	$ —	$ 10
FTRs	22	—	—	—
Forward physicals (power) and tolling arrangements	—	1	—	1
Gas options, swaps and forward arrangements	24	—	—	101
Total	$ 46	$ 44	$ —	$ 112

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, 2007 would increase the fair value of energy options by approximately $34 million; a 10% decrease in energy prices at December 31, 2007, would decrease the fair value by approximately $16 million. A 10% increase in energy prices at December 31, 2007 would increase the fair value of forward physicals (power) and tolling arrangements by approximately $20 million; a 10% decrease in energy prices at December 31, 2007, would decrease the fair value by approximately $20 million. A 10% increase in gas prices at December 31, 2007 would increase the fair value of gas options, swaps and forward arrangements by approximately $71 million; a 10% decrease in gas prices at December 31, 2007, would decrease the fair value by approximately $113 million. A 10% increase in energy prices at December 31, 2007 would increase the fair value of firm transmission rights by approximately $25 million; a 10% decrease in energy prices at December 31, 2007, would decrease the fair value by approximately $19 million.

In July 2007, SCE entered into interest rate-locks to mitigate interest rate risk associated with future financings. Due to declining interest rates in late 2007, at December 31, 2007, these interest rate locks had unrealized losses of $33 million. In January and February 2008, SCE settled interest rate-locks resulting in realized losses of $33 million. A related regulatory asset was recorded in this amount and SCE expects to amortize and recover this amount as interest expense associated with its 2008 financings.

SCE recorded net unrealized gains (losses) of $91 million, $(237) million and $90 million for the years ended December 31, 2007, 2006, and 2005, respectively. The 2007 unrealized gains were primarily due to changes in SCE's gas hedge portfolio mix as well as in increase in the natural gas futures market as of December 31, 2007 compared to December 31, 2006. Due to expected recovery through regulatory mechanisms unrealized gains and losses may temporarily affect cash flows, but are not expected to affect earnings.

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

EMG: LIQUIDITY

Liquidity

At December 31, 2007, EMG and its subsidiaries had cash and cash equivalents and short-term investments of $1.2 billion, EMG had a total of $1.0 billion of available borrowing capacity under its credit facilities. EMG's consolidated debt at December 31, 2007 was $3.95 billion. In addition, EME's subsidiaries had $3.9 billion of long-term lease obligations related to sale-leaseback transactions that are due over periods ranging up to 27 years.

EMG Financing Developments

Senior Notes

On May 7, 2007, EME completed a private offering of $1.2 billion of its 7.00% senior notes due May 15, 2017, $800 million of its 7.20% senior notes due May 15, 2019 and $700 million of its 7.625% senior notes due May 15, 2027. EME pays interest on the senior notes on May 15 and November 15 of each year, beginning on November 15, 2007. On October 22, 2007, EME commenced an exchange offer to exchange the senior notes for an equal principal amount of senior notes which have been registered under the Securities Act. The net proceeds were used, together with cash on hand, to:

- purchase substantially all of EME's outstanding 7.73% senior notes due 2009,
- purchase substantially all of Midwest Generation's 8.75% second priority senior secured notes due 2034,
- repay the outstanding balance of Midwest Generation's senior secured term loan facility ($327.8 million), and
- make a dividend payment of $899 million to MEHC which enabled MEHC to purchase substantially all of its 13.5% senior secured notes due 2008.

The refinancing activities improved EMG's overall liquidity, operating flexibility and ability to capitalize on growth opportunities. EMG recorded a total pre-tax loss of $241 million ($148 million after tax) on early extinguishment of debt during 2007.

Redemption of MEHC Senior Secured Notes

On June 25, 2007, MEHC redeemed in full its senior secured notes. As a result of the redemption, EME is no longer subject to financial and investment restrictions that were contained in the indenture pursuant to which the senior secured notes were issued. Following the redemption, MEHC no longer files reports with the U.S. Securities and Exchange Commission. MEHC does not have any substantive operations.

Credit Agreement Amendments

During the second quarter of 2007, EME amended its existing $500 million secured credit facility, increasing the total borrowings available thereunder to $600 million, and Midwest Generation amended and restated its existing $500 million senior secured working capital facility. The changes to the senior secured working capital facility included a reduction in the interest rate, a longer maturity date, and fewer restrictive covenants. Midwest Generation uses its secured working capital facility to provide credit support for its hedging activities and for general working capital purposes. Midwest Generation can also support its hedging activities by granting liens to eligible hedge counterparties.

Business Development

EME has undertaken a number of activities in 2007 with respect to wind projects, including the following:

- Acquired and/or completed development and commenced construction with completion scheduled for 2008 of seven new wind projects, including:
- the 61 MW Mountain Wind I project and the 80 MW Mountain Wind II project, both located in Wyoming,
- the 38 MW Lookout wind project and the 29 MW Forward wind project, both located in Pennsylvania,
- the 20 MW Odin wind project located in Minnesota,
- the 19 MW Spanish Fork wind project located in Utah, and
- the 150 MW Goat Mountain wind project located in Texas.

The combined estimated capital cost of these projects, excluding capitalized interest, is expected to be approximately $700 million. EME owns 100% of each of these projects, except for the Odin and Goat Mountain wind projects, in which EME owns 99.9%. Each project will, after its completion, use wind to generate electricity from turbines, which will be sold pursuant to the project's power purchase agreement(s) or as a merchant wind generator.

- Completed construction and commenced operations of the 161 MW Wildorado wind project located in Texas in April 2007, the 15 MW Hardin wind project located in Iowa in May 2007, the 21 MW Crosswinds wind project also located in Iowa in June 2007, and the 95 MW Sleeping Bear wind project located in Oklahoma in October 2007.

- In April 2007, EME acquired six projects in development in Texas and Oklahoma totaling 700 MW. These projects are in various stages of development with target completion dates of 2008 and beyond. The purchase price for these projects is comprised of an initial payment and subsequent payments tied to milestones and adjustments based on EME's projected internal rate of return in individual projects. Completion of development of these projects is dependent on a number of items, including, among other things, obtaining power sales agreements, and in certain cases, permits and interconnection agreements.

- In October 2007, EME acquired an option to acquire 100% interests in two wind energy projects under development in Nevada. The projects are in development with target completion dates of 2009 and beyond. The purchase price for these projects is comprised of an initial payment and subsequent payments tied to milestones and adjustments based on EME's projected internal rate of return in individual projects. Completion of development of these projects is dependent on a number of items, including, among other things, obtaining power sales agreements, and in certain cases, permits and interconnection agreements.

- In December 2007, EME entered into a joint development agreement to develop jointly a portfolio of projects (approximately 2,350 MW) located in Arizona, Nevada and New Mexico. Pursuant to the joint development agreement, EME paid $24 million to acquire a 1% interest in twelve designated projects and the option to purchase the remaining 99%. The projects are in development with target completion dates generally beyond 2008. EME is required to fund ongoing development expenses for each project. The purchase price for these projects is comprised of an initial payment and subsequent payments tied to milestones and adjustments based on EME's projected internal rate of return in the individual projects, partially offset by up to $3.4 million per year as a result of the payment of the purchase option. Completion of development of these projects is dependent on a number of items, including, among other things, obtaining power sales agreements, and in certain cases, permits and interconnection agreements.

Capital Expenditures

At December 31, 2007, the estimated capital expenditures through 2010 by EME's subsidiaries related to existing projects, corporate activities and turbine commitments were as follows:

In millions	2008	2009	2010
Illinois Plants			
Plant capital expenditures	$ 63	$ 71	$ 42
Environmental expenditures	46	57	246
Homer City Facilities			
Plant capital expenditures	35	34	26
Environmental expenditures	18	9	9
Wind Projects			
Projects under construction	195	4	—
Turbine commitments	484	540	49
Corporate capital expenditures	20	14	8
Total	**$** 861	**$** 729	**$** 380

Expenditures for Existing Projects

Plant capital expenditures relate to non-environmental projects such as upgrades to boiler and turbine controls, and railroad interconnection, replacement of major boiler components, mill inerting projects and ash site disposal development. Environmental expenditures relate to environmental projects such as mercury emission monitoring and control and a selenium removal system 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 fund these expenditures with debt 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 "Edison International: Management Overview," and "Other Developments — Environmental Matters — Air Quality Regulation — Clean Air Interstate Rule — Illinois," and "Other Developments — Environmental Matters — Air Quality Regulation — Mercury Regulation."

Expenditures for New Projects

EME expects to make substantial investments in new projects during the next several years. At December 31, 2007, EME had committed to purchase turbines (as reflected in the above table of capital expenditures) for wind projects that aggregate 1,166 MW. The turbine commitments generally represent approximately two-thirds of the total capital costs of EME's wind projects. As of December 31, 2007, EME had a development pipeline of potential wind projects with projected installed capacity of approximately 5,000 MW. The development pipeline represents potential projects with respect to which EME either owns the project rights or has exclusive acquisition rights. Completion of development of a wind project may take a number of years due to factors that include local permit requirements, willingness of local utilities to purchase renewable power at sufficient prices to earn an appropriate rate of return, and availability and prices of equipment. Furthermore, successful completion of a wind project is dependent upon obtaining permits, an interconnection agreement(s) or other agreements necessary to support an investment. There is no assurance that each project included in the development pipeline currently or added in the future will be successfully completed.

On February 13, 2008, President Bush signed the Economic Stimulus Act of 2008 which includes a provision for accelerated bonus depreciation for certain capital expenditures acquired and placed in service during 2008. EME expects a portion of its capital expenditures made in 2008 will qualify for this accelerated bonus depreciation which will reduce tax payments for 2008.

Wind Turbine Performance Issues

EME has purchased a significant number of wind turbines in support of its renewable energy activities. The purchases include 475 of 2.1 MW Model S88 wind turbines manufactured by Suzlon Wind Energy Corporation (Suzlon) and 71 of 2.5 MW Model C96 wind turbines manufactured by Clipper Turbine Works, Inc. (Clipper). These turbines are designed to, among other things, improve a project's economics by increasing the size of an individual unit. The turbine suppliers have provided warranties for workmanship, schedule guarantees and performance guarantees during the first five years after a turbine has been commissioned.

After commissioning EME's Sleeping Bear, Hardin and Crosswinds projects, EME and Suzlon identified rotor blade cracks on certain of the Suzlon Model S88 wind turbines at these sites. Suzlon is discussing with EME a remediation plan for these blades, which is expected to include repairing or replacing all Model S88 blades at these projects. Further analysis and testing is required to determine whether the remediation plan will correct the current deficiencies. A delay in completing remediation may adversely affect operating performance of these projects, may delay completion of projects under construction and may subject such projects to damages under the projects' power purchase agreements. Pursuant to the turbine supply contracts with Suzlon, EME expects Suzlon to pay for certain unavailability damages and/or delay damages.

EME purchased Clipper Model C96 wind turbines for its Jeffers project (a 50 MW wind farm located in western Minnesota). During the pre-commissioning phase, Clipper has advised EME to suspend operating the wind turbines at the Jeffers project as a result of rotor blade and gearbox problems experienced at another non-EME wind farm operating with similar Clipper turbines. Clipper has conducted a root cause analysis of these problems, and is in the process of implementing a remediation plan at the Jeffers project to repair and/or replace the affected blades and gearboxes pursuant to its warranty obligations. Delays attributable to the remediation have also delayed completion of the Jeffers project and may subject it to damages under the project's power purchase agreement. Pursuant to the warranty contracts with Clipper, EME expects Clipper to pay certain unavailability damages and/or delay damages.

Although the vendors expect that these efforts will be successful, there is no assurance that repairs will be effective and that expected performance will be achieved. Accordingly, there is no assurance that EME will earn its expected return over the life of the affected projects.

Credit Ratings

Overview

Credit ratings for EMG's direct and indirect subsidiaries at December 31, 2007, were as follows:

	Moody's Rating	S&P Rating	Fitch Rating
EME	B1	BB-	BB-
Midwest Generation	Baa3	BB+	BBB-
EMMT	Not Rated	BB-	Not Rated
Edison Capital	Ba1	BB+	Not Rated

EMG 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. EMG 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.

EMG does not have any "rating triggers" contained in subsidiary financings that would result in it 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—Commodity Price Risk—Energy Price Risk Affecting Sales from the Homer City Facilities."

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. EME has entered into guarantees in support of EMMT's hedging and trading activities; however, because the credit ratings of EMMT and EME are below investment grade, EME has historically also 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, 2007, EMMT had deposited $83 million in cash with brokers in margin accounts in support of futures contracts and had deposited $38 million with counterparties in support of forward energy and transmission contracts. In addition, EME had issued letters of credit of $30 million in support of commodity contracts at December 31, 2007.

Future cash collateral requirements may be higher than the margin and collateral requirements at December 31, 2007, 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, 2007 could increase by approximately $310 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, 2007, Midwest Generation had available $497 million of borrowing capacity under this credit facility. As of December 31, 2007, Midwest Generation had $54 million in loans receivable from EMMT for margin advances. In addition, EME has cash on hand and $507 million of borrowing capacity available under a $600 million working capital facility to provide credit support to subsidiaries.

Intercompany Tax-Allocation Agreement

EME and Edison Capital 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 rights of EME and Edison Capital to receive and the amount of and timing of tax-allocation payments are dependent on the inclusion of EME and Edison Capital 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 EMG's subsidiaries, and other subsidiaries of Edison

International and specific procedures regarding allocation of state taxes. EME and Edison Capital 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 EME's or Edison Capital'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, each of EME and Edison Capital is obligated during periods it generates taxable income, to make payments under the tax-allocation agreements. EME made tax-allocation payments to Edison International of $112 million and $151 million during 2007 and 2006, respectively. Edison Capital received tax-allocation payments from Edison International of $17 million and $135 million during 2007 and 2006, respectively. MEHC (parent) received tax-allocation payments from Edison International of $48 million and $43 million during 2007 and 2006, respectively.

Dividend Restrictions in Major Financings

General

Each of EMG's direct or indirect subsidiaries is organized as a legal entity separate and apart from EMG and its other subsidiaries. Assets of EMG's subsidiaries are not available to satisfy 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 EMG or to its subsidiary holding companies.

Key Ratios of EMG's Principal Subsidiaries Affecting Dividends

Set forth below are key ratios of EME's principal subsidiaries required by financing arrangements at December 31, 2007 or for the twelve months ended December 31, 2007:

Subsidiary	Financial Ratio	Covenant	Actual
Midwest Generation (Illinois plants)	Debt to Capitalization Ratio	Less than or equal to 0.60 to 1	0.23 to 1
EME Homer City (Homer City facilities)	Senior Rent Service Coverage Ratio	Greater than 1.7 to 1	4.16 to 1

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, 2007.

Midwest Generation Financing Restrictions on Distributions

Midwest Generation is bound by the covenants in its credit agreement and 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, enter into swap agreements, or engage in transactions for any speculative purpose. In order for Midwest Generation to make a distribution, it must be in compliance with the covenants specified under its credit agreement, including maintaining a debt to capitalization ratio of no greater than 0.60 to 1.

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 twelve-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, 2007, EME had no borrowings and $93 million of letters of credit outstanding under this credit facility.

EMG: OTHER DEVELOPMENTS

FERC Notice Regarding Investigatory Proceeding against EMMT

In 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 EPAct 2005 and the FERC's rules regarding market behavior, all with respect to certain bidding practices previously employed by EMMT. EMMT is engaged in discussions with the staff to explore the possibility of resolution of this matter. Discussions to date have been constructive and may lead to a settlement agreement acceptable to both parties. Should these discussions not result in a settlement and a formal proceeding commenced, EMMT will be entitled to contest any alleged violations before the FERC and an appropriate court. EME believes that EMMT has complied with all applicable laws and regulations in the bidding practices that it employed and intends to contest vigorously any allegation of violation.

Settlement with Illinois Attorney General

EMMT participated successfully in the first Illinois power procurement auction, held in September 2006 according to rules approved by the Illinois Commerce Commission, and entered into two load requirements services contracts through which it is delivering 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, using contracted supply from Midwest Generation.

Legal actions, including a complaint at the FERC by the Illinois Attorney General and two class action lawsuits, were instituted against successful participants in the 2006 Illinois power procurement auction, including EMMT. On July 24, 2007, Midwest Generation and EMMT, along with other power generation companies and utilities, entered into a settlement agreement with the Illinois Attorney General. Enacting legislation for the settlement was signed on August 28, 2007.

As part of the settlement, Midwest Generation agreed to pay $25 million over three years toward approximately $1 billion in utility customer rate relief and startup costs of the new Illinois Power Agency. The remainder is to be funded by subsidiaries of Exelon Corporation, subsidiaries of Ameren, Dynegy Holdings Inc., and Mid-American Energy Company. Also as part of the settlement, all auction-related complaints filed by the Illinois Attorney General at the FERC, the Illinois Commerce Commission and in the Illinois courts were dismissed and the legislature enacted a rate relief plan.

Midwest Generation made a payment of $7.5 million in September 2007 and is obligated to make monthly payments of $750,000 beginning in January 2008 and continuing until the total commitment has been funded. These payments are non-refundable; however, Midwest Generation's obligations to make the monthly payments will cease if, at any time prior to December 2009, Illinois imposes an electric rate freeze or an additional tax on generators. EME records the payments made under this agreement as an expense when paid.

Midwest Generation Potential Environmental Proceeding

On August 3, 2007, Midwest Generation received an NOV from the US EPA alleging that, beginning in the early 1990's and into 2003, Midwest Generation or Commonwealth Edison performed repair or replacement projects at six Illinois coal-fired electric generating stations in violation of the Prevention of Significant Deterioration requirements and of the New Source Performance Standards of the CAA, including alleged requirements to obtain a construction permit and to install best available control technology at the time of the projects. The US EPA also alleges that Midwest Generation and Commonwealth Edison violated certain operating permit requirements under Title V of the CAA. Finally, the US EPA alleges violations of certain opacity and particulate matter standards at the Illinois plants. The NOV does not specify the penalties or other relief that the US EPA seeks for the alleged violations. Midwest Generation, Commonwealth Edison, the US EPA, and the DOJ are in talks designed to explore the possibility of a settlement. If the settlement talks fail and the DOJ files suit, litigation could take many years to resolve the issues alleged in the NOV. As a result, Midwest Generation is investigating the claims made by the US EPA in the NOV and has identified several defenses which it will raise if the government files suit. At this early stage in the process, Midwest Generation cannot predict the outcome of this matter or estimate the impact on its facilities, its results of operations or financial position.

On August 13, 2007, Midwest Generation and Commonwealth Edison received a letter signed by several Chicago-based environmental action groups stating that, in light of the NOV, the groups are examining the possibility of filing a citizen suit against Midwest Generation and Commonwealth Edison based presumably on the same or similar theories advanced by the US EPA in the NOV.

By letter dated August 8, 2007, Commonwealth Edison advised EME that Commonwealth Edison believes it is entitled to indemnification for all liabilities, costs, and expenses that it may be required to bear as a result of the NOV. By letter dated August 16, 2007, Commonwealth Edison tendered a request for indemnification to EME for all liabilities, costs, and expenses that Commonwealth Edison may be required to bear if the environmental groups were to file suit. Midwest Generation and Commonwealth Edison are cooperating with one another in responding to the NOV.

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: MARKET RISK EXPOSURES

Introduction

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

Commodity Price Risk

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 ability of regional pools to pay market participants' settlement prices for energy and related products;
- 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 "earnings at risk" to identify, measure, monitor and control its overall market risk exposure with respect to hedge positions of the Illinois plants, the Homer City facilities, and the merchant wind projects, and "value at risk" to identify, measure, monitor and control its overall risk exposure in respect of its trading positions. The use of these measures 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, and earnings at risk measures the potential change in value of an asset or position, in each case over a given time interval, under normal market conditions, at a given confidence level. Given the inherent limitations of these measures and relying on a single type of risk measurement tool, EME supplements these approaches 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,
- 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, and
- participation in capacity auctions.

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 addition, Midwest Generation may grant liens on its property in support of hedging transactions associated with 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 "— Credit Risk" below.

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 MISO. 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 megawatt-hour during 2007, 2006 and 2005.

	24-Hour Northern Illinois Hub Historical Energy Prices[1]		
	2007	**2006**	**2005**
January	**$ 35.75**	$ 42.27	$ 38.36
February	**56.64**	42.66	34.92
March	**42.04**	42.50	45.75
April	**48.91**	43.16	38.98
May	**44.49**	39.96	33.60
June	**39.76**	34.80	42.45
July	**43.40**	51.82	50.87
August	**57.97**	54.76	60.09
September	**39.68**	31.87	53.30
October	**50.14**	37.80	49.39
November	**43.25**	41.90	44.03
December	**44.36**	33.57	64.99
Yearly Average	**$ 45.53**	$ 41.42	$ 46.39

[1] Energy prices were calculated at the Northern Illinois Hub delivery point using hourly real-time prices as published by PJM.

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 megawatt-hour for the calendar year 2008 and calendar year 2009 "strips," which are defined as energy purchases for the entire calendar year, as quoted for sales into the Northern Illinois Hub during 2007:

	24-Hour Northern Illinois Hub Forward Energy Prices[1]	
	2008	**2009**
January 31, 2007	$ 44.50	$ 45.15
February 28, 2007	44.99	44.85
March 31, 2007	47.92	46.59
April 30, 2007	49.89	49.73
May 31, 2007	50.69	50.46
June 30, 2007	46.09	47.02
July 31, 2007	46.90	48.50
August 31, 2007	44.57	46.49
September 30, 2007	46.80	48.70
October 31, 2007	50.27	51.63
November 30, 2007	47.70	50.37
December 31, 2007	48.06	51.50

(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 (primarily based on prices at the Northern Illinois Hub) at December 31, 2007:

	2008	2009	2010
Energy Only Contracts[1]			
MWh	10,837,600	7,692,290	3,471,950
Average price/MWh[2]	$ 61.27	$ 62.38	$ 62.62
Load Requirements Services Contracts			
Estimated MWh[3]	5,613,433	1,631,859	—
Average price/MWh[4]	$ 64.01	$ 63.65	$ —
Total estimated MWh	16,451,033	9,324,149	3,471,950

(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, 2007 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.

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 NYISO markets.

The following table depicts the average historical market prices for energy per megawatt-hour 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		
	2007	2006	2005	**2007**	2006	2005
January	**$ 40.30**	$ 48.67	$ 45.82	**$ 44.63**	$ 54.57	$ 49.53
February	**64.27**	49.54	39.40	**73.93**	56.39	42.05
March	**55.00**	53.26	47.42	**61.02**	58.30	49.97
April	**52.42**	48.50	44.27	**58.74**	49.92	44.55
May	**48.12**	44.71	43.67	**53.89**	48.55	43.64
June	**45.88**	38.78	46.63	**60.19**	45.78	53.72
July	**48.23**	53.68	54.63	**58.89**	63.47	66.34
August	**55.44**	58.60	66.39	**71.00**	76.57	82.83
September	**48.90**	33.26	66.67	**60.14**	34.40	76.82
October	**53.89**	37.42	67.93	**61.11**	39.65	77.56
November	**47.27**	40.13	59.78	**55.25**	44.83	62.01
December	**52.58**	35.29	75.03	**59.67**	40.53	81.97
Yearly Average	**$ 51.03**	$ 45.15	$ 54.80	**$ 59.87**	$ 51.08	$ 60.92

[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 megawatt-hour for the calendar year 2008 and calendar year 2009 "strips," which are defined as energy purchases for the entire calendar year, as quoted for sales into the PJM West Hub during 2007:

	24-Hour PJM West Hub Forward Energy Prices[1]	
	2008	2009
January 31, 2007	$ 58.09	$ 56.40
February 28, 2007	59.33	57.96
March 31, 2007	63.37	61.44
April 30, 2007	65.73	64.37
May 31, 2007	66.57	65.97
June 30, 2007	62.36	64.07
July 31, 2007	62.89	64.89
August 31, 2007	58.96	62.45
September 30, 2007	61.71	64.53
October 31, 2007	65.97	67.92
November 30, 2007	62.14	65.89
December 31, 2007	62.49	67.13

(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 EME Homer City's hedge position at December 31, 2007:

	2008	**2009**	**2010**
MWh	7,232,000	2,867,200	1,022,400
Average price/MWh[1]	$ 60.85	$ 73.84	$ 77.80

(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 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, 2007 is not directly comparable to the 24-hour PJM West Hub prices set forth above.

The average price/MWh for EME 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.

Capacity Price Risk

On June 1, 2007, PJM implemented the RPM for capacity. The purpose of the RPM is to provide a long-term pricing signal for capacity resources. The RPM provides a mechanism for PJM to satisfy the region's need for generation capacity, the cost of which is allocated to load-serving entities through a locational reliability charge.

The following table summarizes the status of capacity sales for Midwest Generation and EME Homer City at December 31, 2007:

	January 1, 2008 to May 31, 2008		June 1, 2008 to May 31, 2009		June 1, 2009 to May 31, 2010	
	Midwest Generation	EME Homer City	Midwest Generation	EME Homer City	Midwest Generation	EME Homer City
Fixed Price Capacity Sales						
Through RPM Auction,						
Net MW	2,603	786	3,283	820	4,614	1,670
Price per MW-day	$ 40.80	$ 40.80	$ 111.92	$ 111.92	$ 102.04	$ 191.32
Non-unit Specific Capacity Sales						
MW	500	—	880	—	715	—
Price per MW-day	$ 21.31	—	$ 64.35	—	$ 71.46	—
Variable Capacity Sales						
MW	—	891	—	891	—	—
Price per MW-day	—	$ 66.71(1)	—	$ 69.50(2)	—	—

(1) Actual contract price is a function of NYISO capacity auction clearing prices in January through April 2008 and forward over-the-counter NYISO capacity prices on December 31, 2007 for May 2008.

(2) Expected price per MW-day is based on forward over-the-counter NYISO prices on December 31, 2007.

In January 2008, the RPM auction took place for the time period from June 1, 2010 through May 31, 2011 which resulted in a fixed price for Midwest Generation and EME Homer City's capacity sold into the auction of $174.29/MW-day. EMMT sold net 4,929 MW of capacity from the Illinois plants and net 1,813 MW of capacity from the Homer City facilities.

Revenue from the sale of capacity from Midwest Generation and EME Homer City beyond the periods set forth above will depend upon the amount of capacity available and future market prices either in PJM or nearby markets if EME has an opportunity to capture a higher value associated with those markets. Under PJM's RPM system, the market price for capacity is generally determined by aggregate market-based supply conditions and an administratively set aggregate demand curve. Among the factors influencing the supply of capacity in any particular market are plant forced outage rates, plant closings, plant delistings (due to plants being removed as capacity resources and/or to export capacity to other markets), capacity imports from other markets, and the cost of new entry.

Midwest Generation entered into hedge transactions in advance of the RPM auctions with counterparties that are settled through PJM. In addition, the load service requirements contracts entered into by Midwest Generation with Commonwealth Edison include energy, capacity and ancillary services (sometimes referred to as a "bundled product"). Under PJM's business rules, Midwest Generation sells all its available capacity (defined as unit capacity less forced outages) into the RPM and is subject to a locational reliability charge for the load under these contracts. This means that the locational reliability charge generally offsets the related amounts sold in the RPM, which Midwest Generation presents on a net basis in the table above.

Prior to the RPM auctions for the relevant delivery periods, EME Homer City sold a portion of its capacity to an unrelated third party for the delivery periods from June 1, 2007 through May 31, 2008 and June 1, 2008 through May 31, 2009. EME Homer City is not receiving the RPM auction clearing price for this previously sold capacity. The price EME Homer City is receiving for these capacity sales is a function of NYISO capacity clearing prices resulting from separate NYISO capacity auctions.

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. Effective June 1, 2007, PJM implemented marginal losses which adjust the algorithm that calculates locational marginal prices to include a component for marginal transmission losses in addition to the component included for congestion. 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 2007, 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 15%, compared to 12% during 2006 and 10% during 2005. The monthly average difference during 2007 ranged from 10% to 24%. 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, although the implementation of marginal losses on June 1, 2007 has lowered energy prices at the Illinois plants busbars.

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 may purchase financial transmission rights and basis swaps in PJM for EME Homer City. 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 and Transportation 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, 2007 for the next three years.

	Amount of Coal Under Contract in Millions of Tons[(1)]		
	2008	2009	2010
Illinois plants	17.5	11.7	11.7
Homer City facilities	5.7	4.4	0.3

(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.

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, increased steadily during 2007 and decreased slightly in 2006 from 2005. 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 (MMBtu) sulfur content) ranged from $44.00 per ton to $55.25 per ton during 2007 and increased to a price of $70.00 per ton at February 15, 2008, as reported by the Energy Information Administration (EIA). The 2007 increase in the NAPP coal price was in line with normal market price volatility. In 2006, the price of NAPP coal fluctuated between $37.50 per ton and $45.00 per ton, with a price of $43.00 per ton at December 15, 2006, as reported by the EIA. 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 EIA. 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.

The price of PRB coal (with 8,800 Btu per pound heat content and 0.8 pounds of SO_2 per MMBtu sulfur content) purchased for the Illinois plants increased during 2007 from 2006 year-end prices. The 2007 fluctuations in PRB coal prices were in line with normal market price volatility. Prices of PRB coal decreased during 2006 from 2005 due to easing natural gas prices, fuel switching, lower prices for SO_2 allowances and improved inventory. The price of PRB coal fluctuated between $8.35 per ton to $11.50 per ton during 2007 and increased to a price of $13.10 per ton at February 15, 2008, as reported by the EIA. In 2006, prices ranged from $20.66 per ton in January 2006 to $9.90 per ton at December 15, 2006. In 2005, the price of PRB coal ranged from $6.20 per ton to $18.48 per ton, as reported by the EIA.

EME has contractual agreements for the transport of coal to its facilities. The primary contract is with Union Pacific Railroad (and various delivering carriers), which extends through 2011. EME is exposed to price risk related to higher transportation rates after the expiration of its existing transportation contracts. Current transportation rates for PRB coal are higher than the existing rates under contract (transportation costs are more than 50% of the delivered cost of PRB coal to the Illinois plants).

Based on EME's anticipated coal requirements in 2008 in excess of the amount under contract, EME expects that a 10% change in the price of coal at December 31, 2007 would increase or decrease pre-tax income in 2008 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 NO_X SIP Call requirement. 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. 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.

The average price of purchased SO_2 allowances was $512 per ton during 2007, $664 per ton during 2006 and $1,219 per ton during 2005. The decrease in the price of SO_2 allowances during 2007 from 2006 year-end prices has been attributed to less demand in the market for SO_2 allowances. The 2006 decrease in the price of SO_2 allowances has been attributed to a decline in natural gas prices and fuel switching from oil to gas. The price of SO_2 allowances, determined by obtaining broker quotes and information from other public sources, was $535 per ton as of December 31, 2007. EME does not anticipate any requirements to purchase SO_2 emission allowances in 2008. See "Other Developments — Environmental Matters" for a discussion of environmental regulations related to emissions.

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 "Critical Accounting Estimates and Policies—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 non-qualifying 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 operating 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 non-trading activities for the three-year period ended December 31, 2007:

In millions Year ended December 31,	2007	2006	2005
Non-qualifying hedges			
Illinois plants	**$ (14)**	$ 28	$ (17)
Homer City	**(1)**	2	(1)
Ineffective portion of cash flow hedges			
Illinois plants	**(11)**	2	(2)
Homer City	**(9)**	33	(40)
Total unrealized gains (losses)	**$ (35)**	$ 65	$ (60)

At December 31, 2007, unrealized losses of $38 million were recognized from non-qualifying hedge contracts or the ineffective portion of cash flow hedges related to subsequent periods ($25 million for 2008, $10 million for 2009, and $3 million for 2010).

Fair Value of Financial Instruments

Non-Trading 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,	2007	2006
Commodity price:		
Electricity	**$ (137)**	$ 184

In assessing the fair value of EME's non-trading derivative financial instruments, EME uses a variety of methods and assumptions based on the market conditions and associated risks existing at each balance sheet date. The fair value of commodity price contracts takes into account quoted market prices, time value of money, volatility of the underlying commodities and other factors. The change in fair value of electricity contracts at December 31, 2007 as compared to December 31, 2006 is attributable to an increase in the average market prices for power as compared to contracted prices at December 31, 2007, which is the valuation date, causing the fair value of the contracts to become liabilities instead of assets. A 10% change in the market price at December 31, 2007 would increase or decrease the fair value of outstanding derivative commodity price contracts by approximately $210 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, 2007:

In millions	Total Fair Value	Maturity <1 year	Maturity 1 to 3 years	Maturity 4 to 5 years	Maturity >5 years
Prices actively quoted	$ (137)	$ (41)	$ (96)	$ —	$ —

Energy Trading Derivative Financial Instruments

The fair value of the commodity financial instruments related to energy trading activities as of December 31, 2007 and 2006 are set forth below:

	December 31, 2007		December 31, 2006	
In millions	Assets	Liabilities	Assets	Liabilities
Electricity	**$ 141**	**$ 9**	$ 313	$ 207
Other	**—**	**—**	5	—
Total	**$ 141**	**$ 9**	$ 318	$ 207

The change in the fair value of trading contracts for the year ended December 31, 2007 was as follows:

In millions	
Fair value of trading contracts at January 1, 2007	**$ 111**
Net gains from energy trading activities	**149**
Amount realized from energy trading activities	**(133)**
Other changes in fair value	**5**
Fair value of trading contracts at December 31, 2007	**$ 132**

A 10% change in the market price at December 31, 2007 would increase or decrease the fair value of trading contracts by approximately $44 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, 2007):

In millions	Total Fair Value	Maturity <1 year	Maturity 1 to 3 years	Maturity 4 to 5 years	Maturity >5 years
Prices actively quoted	$ 51	$ 44	$ 7	$ —	$ —
Prices based on models and other valuation methods	81	4	16	22	39
Total	**$ 132**	**$ 48**	**$ 23**	**$ 22**	**$ 39**

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 non-performing counterparty were unable to pay the resulting liquidated damages owed to EME. Further, EME would be exposed to the risk of non-payment of accounts receivable accrued for products delivered prior to the time 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, 2007, the amount of exposure as described above, broken down by the credit ratings of EME's counterparties, was as follows:

In millions	December 31, 2007
S&P Credit Rating A or higher	$ 40
A-	61
BBB+	81
BBB	16
BBB-	4
Below investment grade	1
Total	**$ 203**

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 51% of EME's consolidated operating revenue for the year ended December 31, 2007. 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 non-investment grade companies. Any losses due to a PJM member default are shared by all other members based upon a predetermined formula. At December 31, 2007, EME's account receivable due from PJM was $82 million.

Beginning in January 2007, EME also derived a significant source of its revenue from the sale of energy, capacity and ancillary services generated at the Illinois plants to Commonwealth Edison under load requirements services contracts. Sales under these contracts accounted for 19% of EME's consolidated operating revenue for the year ended December 31, 2007. Commonwealth Edison's senior unsecured debt rating was downgraded below investment grade by S&P in June 2007 and by Moody's in March 2007. As a result, Commonwealth Edison is required to pay EME twice a month for sales under these contracts. At December 31, 2007, EME's account receivable due from Commonwealth Edison was $20 million.

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.

At December 31, 2007, Edison Capital had a net leveraged lease investment, before deferred taxes, of $54 million in three aircraft leased to American Airlines. Although American Airlines has reported a profit in 2006 and 2007, 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, 2007, American Airlines was current in its lease payments to Edison Capital.

Interest Rate Risk

Interest rate changes can affect earnings and the cost of capital for capital improvements or new investments in power projects. EMG 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. The fair market values of long-term fixed interest rate obligations are subject to interest rate risk. The fair market value of EMG's consolidated long-term obligations (including current portion) was $3.91 billion at December 31, 2007, compared to the carrying value of $3.95 billion. A 10% increase in market interest rates at December 31, 2007 would result in a decrease in the fair value of EMG's consolidated long-term obligations by approximately $190 million. A 10% decrease in market interest rates at December 31, 2007 would result in an increase in the fair value of EMG's consolidated long-term obligations by approximately $205 million.

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. As of December 31, 2007, Edison Capital had investments in Latin America, Asia and Emerging Europe of $22 million, $16 million and $22 million, respectively. Edison Capital, through these investments, is exposed to foreign exchange risk in the currency of the ultimate investment.

Edison Capital's cross-border leases are denominated in U.S. dollars and, therefore, are not exposed to foreign currency 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, 2007, Edison International (parent) had no debt outstanding (excluding intercompany related debt).

Edison International (parent)'s cash requirements for the 12-month period following December 31, 2007 are expected to consist of:

- Dividends to common shareholders. The Board of Directors of Edison International declared a $0.29 per share quarterly dividend which was paid in January 2007, April 2007, July 2007, and October 2007, respectively, and a $.305 per share quarterly dividend which was declared in December 2007 and paid in January 2008;
- Intercompany related debt; and
- General and administrative expenses.

Edison International (parent) expects to meet its continuing obligations through cash and cash equivalents on hand, borrowings and dividends and/or borrowings from its subsidiaries. At December 31, 2007, Edison International (parent) had approximately $37 million of cash and cash equivalents on hand. 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. At December 31, 2007, the entire credit facility was available for liquidity purposes. 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 (see "SCE: Liquidity—Dividend Restrictions and Debt Covenants" for further discussion). 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. The Board of Directors of SCE declared a $25 million dividend which was paid in January 2008.

EMG's ability to pay dividends is dependent on its subsidiaries' ability to pay dividends to EMG. EME's corporate credit facility contains covenants that restrict its ability, and the ability of several of its subsidiaries, to pay dividends in the case of any event of default under the facility. As of December 31, 2007, EME was not in default under its credit facility. In addition, see "EMG: Liquidity—Dividend Restrictions in Major Financings" for further discussion. During 2007, EMG made dividend payments of $238 million to Edison International from distributions received from Edison Capital. Edison Capital loaned $50 million to Edison International in 2007, and an additional $120 million in January 2008.

EDISON INTERNATIONAL (PARENT): OTHER DEVELOPMENTS

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 the 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, 2007, 2006, and 2005, and the relative contributions by its subsidiaries.

		Earnings (Loss)	
In millions **Year Ended December 31,**	**2007**	**2006**	**2005**
Earnings (Loss) from Continuing Operations:			
SCE	**$ 707**	$ 776	$ 725
EMG	**412**	334	414
Edison International (parent) and other	**(19)**	(27)	(31)
Edison International Consolidated Earnings from Continuing Operations	**1,100**	1,083	1,108
Earnings (Loss) from Discontinued Operations	**(2)**	97	30
Cumulative effect of accounting change – net of tax	**—**	1	(1)
Edison International Consolidated	**$ 1,098**	$ 1,181	$ 1,137

Earnings (Loss) from Continuing Operations

2007 vs. 2006

SCE's earnings from continuing operations were $707 million in 2007, compared with earnings of $776 million in 2006. The decrease was mainly due to a $130 million benefit related primarily to favorable resolution of tax and regulatory matters and $28 million of generator settlements, both recognized in 2006, and higher net interest expense in 2007. The decrease was partially offset by a $31 million benefit recognized in 2007, primarily related to the income tax treatment of certain costs including those associated with environmental remediation, higher operating margin, lower income taxes in 2007 and a tariff dispute settlement.

EMG's earnings from continuing operations were $412 million in 2007, compared with earnings of $334 million in 2006. The increase primarily reflects higher operating income at EMG's Illinois plants and EMG's Homer City facilities, lower interest expense, and higher project income and trading margin. This increase was partially offset by higher development and other corporate costs and lower earnings from Edison Capital. Both 2007 and 2006 results were impacted by early debt extinguishment costs of $148 million and $90 million, respectively.

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. EMG'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, and lower gains from Edison Capital's global infrastructure fund investments. These decreases were partially offset by the favorable SFAS No. 133 net impact, lower interest expense, a charge of $34 million recorded in 2005 related to the March Point project and lower net corporate interest expense and a gain on the sale of an affordable housing project. EMG had SFAS No. 133 unrealized gains of $39 million (after tax) in 2006, compared to unrealized losses of $35 million (after tax) in 2005.

Operating Revenue

Electric Utility Revenue

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

In millions	**2007 vs. 2006**	**2006 vs. 2005**
Electric utility revenue		
Rate changes and impact of tiered rate structure (including unbilled)	**$ (545)**	$ 1,441
Sales volume changes (including unbilled)	**119**	311
Balancing account over/under collections	**405**	(422)
Sales for resale	**120**	(463)
SCE's VIEs	**(6)**	(75)
Other (including inter company transactions)	**71**	20
Total	**$ 164**	$ 812

SCE's retail sales represented approximately 87%, 88% and 82% of electric utility revenue for the years ended December 31, 2007, 2006, and 2005, respectively. Due to warmer weather during the summer months and SCE's rate design, electric utility revenue during the third quarter of each year is generally higher than other quarters.

Total electric utility revenue increased by $164 million in 2007 compared to 2006 (as shown in the table above). The variances for the revenue components are as follows:

- Electric utility revenue from rate changes decreased mainly from the redesign of SCE's tiered rate structure which resulted in a decrease of residential rates in the higher tiers. Effective February 14, 2007, SCE's system average rate decreased to 13.9¢ per-kWh (including 3.0¢ per-kWh related to CDWR) mainly as the result of projected lower natural gas prices in 2007, as well as the refund of overcollections in the ERRA balancing account that occurred in 2006 from lower than expected natural gas prices and higher than expected summer 2006 sales volume (see "SCE: Regulatory Matters — Current Regulatory Developments — Impact of Regulatory Matters on Customer Rates," and " — Energy Resource Recovery Account Proceedings" for further discussion of these rate changes).
- Electric utility revenue resulting from sales volume changes was mainly due to customer growth as well as an increase in customer usage.
- SCE recognizes revenue, subject to balancing account treatment, equal to the amount of the actual costs incurred and up to its authorized revenue requirement. Any revenue collected in excess of actual power procurement-related costs incurred or above the authorized revenue requirement is not recognized as revenue and is deferred and recorded as regulatory liabilities to be refunded in future customer rates.

Revenue collected below the authorized revenue requirement is recognized as revenue and recorded as a regulatory asset for future recovery. Power procurement-related costs incurred in excess of revenue billed are deferred in a balancing account and recorded as regulatory assets for recovery in future customer rates. In 2007, SCE deferred approximately $95 million compared to a deferral of approximately $515 million in 2006. The decrease in deferred revenue was mainly due to lower net overcollections (lower deferred costs partially offset by lower revenue collections of SCE's authorized revenue requirement) resulting from lower gas prices as compared to forecast and lower revenue in 2007 resulting from warmer weather in 2006.

- 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 increased due to higher excess energy in 2007, compared to 2006. Revenue from sales for resale is refunded to customers through the ERRA balancing account and does not impact earnings.
- The increase in other revenue was primarily due to higher net investment earnings from SCE's nuclear decommissioning trusts. Due to regulatory treatment, 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 $812 million in 2006 compared to 2005 (as shown in the table above). The variances for the revenue components are as follows:

- Electric utility revenue from rate changes was mainly due to rate increases implemented throughout 2006, 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.
- 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.
- In 2006, SCE collected revenue in excess of actual costs incurred and as a result deferred approximately $515 million compared to a deferral of 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. Due to regulatory treatment, the nuclear decommissioning trust investment earnings are offset in depreciation, decommissioning and amortization expense and as a result, have no impact on net income.

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 $2.3 billion, $2.5 billion, and $1.9 billion for the years ended December 31, 2007, 2006, and 2005, respectively.

Nonutility Power Generation Revenue

The following table sets forth the major changes in nonutility power generation revenue:

In millions **For the Year Ended December 31,**	**2007**	2006	2005
EMG's Illinois plants	**$ 1,579**	$ 1,399	$ 1,429
EMG's Homer City facilities	**764**	642	592
EMMT	**143**	130	195
Other	**89**	57	32
Nonutility power generation	**$ 2,575**	$ 2,228	$ 2,248

Nonutility power generation revenue increased $347 million in 2007 compared to 2006 and decreased $20 million in 2006 compared to 2005.

Nonutility power generation revenue from EMG's Illinois plants increased $180 million in 2007, and decreased $30 million in 2006. The 2007 increase was attributable to higher energy revenue resulting from higher average realized energy prices and slightly higher generation in 2007, as compared to 2006. Nonutility power generation revenue from EMG's Illinois plants was also adversely affected by an increase in unrealized losses in 2007 related to hedge contracts discussed below. The 2006 decrease in earnings was primarily attributable to lower energy revenue resulting from lower generation. Partially offsetting these decreases was an increase in unrealized gains in 2006 related to hedge contracts discussed below.

EMG's Illinois plants recorded unrealized gains (losses) of $(25) million in 2007, $30 million in 2006, and $(19) million in 2007, 2006, and 2005, respectively. Unrealized gains and losses are primarily due to power contracts that did not qualify for hedge accounting under SFAS No. 133 (sometimes referred to as economic hedges). These energy contracts were entered into to hedge the price risk related to projected sales of power. During 2007, power prices increased, resulting in mark-to-market losses on economic hedges. At December 31, 2007, unrealized losses of $18 million were recognized from economic hedges and from the ineffective portion of cash flow hedges related to subsequent periods. The ineffective portion of hedge contracts at the Illinois plants was primarily attributable to changes in the difference between energy prices at NiHub (the settlement point under forward contracts) and the energy prices at the Illinois plants busbars (the delivery point where power generated by the Illinois plants is delivered into the transmission system) resulting from marginal losses. During 2005, power prices increased, resulting in mark-to-market losses on economic hedges. As economic hedge contracts were settled in 2006 the previous unrealized losses resulted in unrealized gains. See "EMG: Market Risk Exposures — Commodity Price Risk" for more information regarding forward market prices.

Nonutility power generation from EMG's Homer City facilities increased $122 million for 2007 and increased $50 million in 2006. The 2007 increase was primarily attributable to an increase in energy revenue from higher generation and average realized energy prices, and an increase in capacity revenue resulting from the PJM RPM auction. Nonutility power generation revenue from EMG's Homer City facilities was adversely affected due to the timing of unrealized gains and losses related to hedge contracts discussed below. The 2006 increase was primarily attributable to the timing of unrealized gains and losses related to hedge contracts discussed below and higher average realized energy prices. Partially offsetting these increases were lower generation in 2006 due to the unplanned outage at Unit 3. On January 29, 2006, the main power transformer on Unit 3 of the EMG 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. The Unit 3 outage reduced the amount of generation during 2006.

EMG's Homer City facilities recorded unrealized gains (losses) from hedge activities of $(10) million, $35 million and $(41) million in 2007, 2006, and 2005, respectively. Unrealized gains and losses were primarily attributable to the ineffective portion of forward and futures contracts which are derivatives that qualify as cash flow hedges under SFAS No. 133. The ineffective portion of hedge contracts at Homer City was primarily attributable to changes in the difference between energy prices at 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, 2007, unrealized losses of $21 million were recognized primarily from the ineffective portion of cash flow hedges related to subsequent periods. See "EMG: Market Risk Exposures — Commodity Price Risk" for more information regarding forward market prices.

EME seeks to generate profit by utilizing its subsidiary, EMMT, to engage in trading activities in those markets in which it is active as a result of its management of the merchant power plants of Midwest Generation and Homer City. EMMT trades power, fuel and transmission congestion primarily in the eastern power grid using products available over the counter, through exchanges and from ISOs. Nonutility power generation revenue from energy trading activities at EMMT increased $13 million in 2007 and decreased $65 million in 2006. The increase in nonutility power generation revenue from energy trading activities was primarily attributable to higher revenue from financial transmission rights used at specific delivery points in the eastern power grid and higher revenue from energy trading in the over-the-counter markets. 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.

EMG's other projects increased by $32 million in 2007 compared to an increase of $25 million in 2006. The 2007 increase in revenue in other projects was primarily due to the Wildorado wind project. Commercial operation of the Wildorado wind project commenced during April 2007.

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 EMG's Illinois plants and Homer City facilities vary substantially on a seasonal basis. In addition, maintenance outages generally are scheduled during periods of lower projected electric demand (spring and fall) further reducing generation and increasing major maintenance costs which are recorded as an expense when incurred. Accordingly, nonutility power generation revenue from EMG's Illinois plants and Homer City facilities are seasonal and have significant variability from quarter to quarter. Seasonal fluctuations may also be affected by changes in market prices. See "EMG: Market Risk Exposures — 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,**	**2007**	**2006**	**2005**
SCE	**$ 1,191**	$ 1,112	$ 1,193
EMG	**684**	645	617
Edison International Consolidated	**$ 1,875**	$ 1,757	$ 1,810

SCE's fuel expense increased $79 million in 2007 and decreased $81 million in 2006. The 2007 increase was mainly due to an increase at SCE's Mountainview plant of $70 million, due to higher generation and higher gas costs in 2007 compared to 2006; higher nuclear fuel expense of $20 million in 2007 resulting primarily from a planned refueling and maintenance outage at SCE's San Onofre Unit 2 and 3 in 2006; partially offset by lower fuel expense of approximately $15 million, related to the SCE VIE projects. 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.

EMG's fuel expense increased $39 million in 2007 and $28 million in 2006. The 2007 increase was mainly due to higher coal consumption in 2007, as compared to 2006, resulting from higher generation at both EMG's Illinois plants and Homer City facilities. The 2007 increase at the Homer City facilities was partially offset by lower cost of SO_2 emission allowances. The 2006 increase was mainly due to higher coal prices, partially offset by lower prices of SO_2 emission allowances at EMG's Homer City facilities and lower generation.

Purchased-Power Expense

The following is a summary of purchased-power expense:

In millions **For the Year Ended December 31,**	**2007**	**2006**	**2005**
Purchased power	**$ 3,117**	$ 3,013	$ 3,113
Unrealized (gains) losses on economic hedging activities – net	**(91)**	237	(90)
Realized (gains) losses on economic hedging activities – net	**132**	339	(115)
Energy settlements and refunds	**(34)**	(180)	(286)
Total purchased-power expense	**$ 3,124**	$ 3,409	$ 2,622

Total purchased-power expense decreased $285 million in 2007 and increased $787 million in 2006.

Purchased power, in the table above, increased $104 million in 2007 compared to a decrease of $100 million in 2006. The 2007 increase was due to higher bilateral energy purchases of $230 million, resulting from higher costs per kWh and increased kWh purchases from new contracts entered into in 2007; higher QF purchased-power expense of $60 million, resulting from an increase in the average spot natural gas prices (as discussed further below); and higher firm transmission right costs of $40 million. The 2007 increase was partially offset by a decrease in ISO-related energy costs of $150 million and $60 million in purchased power expense associated with power contracts that were modified under EITF No. 01-8 in 2006 (see "— Commitments, Guarantees, and Indemnities" for further discussion). The 2006 decrease in purchased power resulted from lower power purchased and lower prices from QFs of approximately $95 million (as further discussed below).

Net realized and unrealized losses on economic hedging activities, in the table above, was $41 million in 2007 compared to $576 million in 2006 (see "SCE: Market Risk Exposures — Commodity Price Risk" for further discussion). The changes in net realized and unrealized (gains) losses on economic hedging activities primarily resulted from changes in SCE's gas hedge portfolio mix as well as an increase in the natural gas futures market as of December 31, 2007, compared to December 31, 2006. Due to expected recovery through regulatory mechanisms realized and unrealized gains and losses may temporarily affect cash flows, but are not expected to affect earnings (see "SCE: Market Risk Exposures — Commodity Price Risk" for further discussion).

SCE energy settlement refunds and generator settlements decreased in 2007 by $146 million compared to $106 million in 2006 (See "SCE: Regulatory Matters — Current Regulatory Developments — FERC Refund Proceedings" for further discussion).

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 are at a fixed price of 6.15¢ per-kWh, effective May 2007.

Provisions for Regulatory Adjustment Clauses – Net

Provisions for regulatory adjustment clauses – net increased $246 million in 2007 and decreased $410 million in 2006. The 2007 variance reflects net unrealized gains on economic hedging activities of approximately $91 million in 2007, compared to net unrealized losses on economic hedging activities of approximately $237 million in 2006 (mentioned above in purchased-power expense). The 2007 variance also reflects approximately $70 million in energy refunds and generator settlements recorded in 2006; the resolution of a $135 million one-time gain related to a portion of revenue collected during the 2001 – 2003 period related to state income taxes recorded in the second quarter of 2006; $60 million associated with power contracts that were modified under EITF No. 01-8 in 2006 (see "— Commitments, Guarantees, and Indemnities" for further discussion); and approximately $255 million in operation and maintenance-related expenses resulting from timing differences that are being recognized in revenue which are being recovered through regulatory mechanisms.

The 2006 decrease was mainly due to net unrealized losses related to economic hedging transactions 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 purchased power, fuel, and operation and maintenance expenses of approximately $240 million.

Other Operation and Maintenance Expense

In millions **For the Year Ended December 31,**	**2007**	**2006**	**2005**
SCE	**$ 3,056**	$ 2,884	$ 2,716
EMG	**980**	840	865
Edison International (parent) and other	**31**	38	28
Edison International Consolidated	**$ 4,067**	$ 3,762	$ 3,609

SCE's other operation and maintenance expense increased $172 million in 2007 and $168 million in 2006. Certain of SCE's operation and maintenance expense accounts are recovered through regulatory mechanisms approved by the CPUC. The costs associated with these regulatory balancing accounts increased $98 million in 2007 mainly related to both higher demand-side management and energy efficiency costs partially offset by lower must-run and must-offer obligation costs related to the reliability of the ISO systems. In addition to the increase in balancing account related operation and maintenance costs the 2007 increase was due to higher transmission and distribution maintenance cost of approximately $20 million; higher health care costs and other benefits of $30 million; higher uncollectible accounts of $10 million; and higher legal costs of $20 million. The 2007 increase was partially offset by lower generation-related costs of approximately $20 million in 2007 resulting from the planned refueling and maintenance outages at SCE's San Onofre Units 2 and 3 in the first quarter 2006. 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 costs 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.

EMG's other operation and maintenance expense increased $140 million in 2007 and decreased $25 million in 2006. The 2007 increase was mainly due to higher planned maintenance costs at EMG's Illinois plants, higher development costs incurred in 2007 (mostly related to wind projects), higher corporate expenses and loss accruals. The 2007 increase was also due to higher maintenance costs in 2007 and unplanned outages at the Powerton Station. On November 2, 2007, Unit 5 at the Powerton Station had an unplanned outage related to a low pressure turbine. The turbine was repaired and the unit was returned to service on December 13, 2007. On December 18, 2007, Unit 6 at the Powerton Station had a duct and fan failure resulting in a suspension of operations at this unit through January 4, 2008 when the unit returned at half-load capability. Scheduled maintenance work for the spring of 2008 was accelerated to minimize the aggregate impact of the outage. Repairs were completed on February 13, 2008 and the unit has been returned to service. The 2006 decrease was mainly due to a reduction in Edison Capital's credit reserve requirements and the integration of Edison Capital's management and personnel with EMG. The 2006 decrease was partially offset by an increase of approximately $10 million due to higher plant overhaul costs at EMG's Illinois plants.

Depreciation, Decommissioning and Amortization Expense

In millions **For the Year Ended December 31,**	**2007**	**2006**	**2005**
SCE	**$ 1,094**	$ 1,026	$ 915
EMG	**170**	155	146
Edison International Consolidated	**$ 1,264**	$ 1,181	$ 1,061

SCE's depreciation, decommissioning and amortization expense increased $68 million in 2007 and increased $111 million in 2006. The 2007 increase was primarily due to transmission and distribution asset additions resulting in increased depreciation expense of $50 million (see "SCE: Liquidity — Capital Expenditures" for a further discussion). The 2007 increase also reflects a $25 million increase in nuclear decommissioning trust earnings net of other-than-temporary impairment losses associated with the nuclear decommissioning trust funds. Due to its regulatory treatment, investment impairment losses and trust earnings are recorded in electric utility revenue and are offset in decommissioning expense and have no impact on net income. 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.

EMG's depreciation and amortization expense increased $15 million in 2007 and increased $9 million in 2006. The 2007 increase was primarily attributable to higher depreciation expense for wind projects.

Other Income and Deductions

Interest and dividend income

In millions **For the Year Ended December 31,**	**2007**	**2006**	**2005**
SCE	**$ 39**	$ 51	$ 38
EMG	**112**	115	70
Edison International (parent) and other	**3**	3	4
Edison International Consolidated	**$ 154**	$ 169	$ 112

SCE's interest income decreased $12 million in 2007 and increased $13 million in 2006. The 2007 decrease was mainly due to lower interest income resulting from lower undercollections on balancing accounts in 2007, as compared to 2006. The 2006 increase was mainly due to interest income from balancing accounts that were undercollected during both 2006 and 2005, and higher short-term interest rates in 2006, as compared to 2005.

EMG's interest and dividend income increased $45 million in 2006 primarily due to higher interest income resulting from higher interest rates in 2006 compared to 2005.

Equity in Income from Partnerships and Unconsolidated Subsidiaries – Net

Equity in income from partnerships and unconsolidated subsidiaries – net decreased $57 million in 2006 mainly due to lower earnings of approximately $50 million from Edison Capital's global infrastructure funds due to higher gains in 2005.

Other Nonoperating Income

In millions For the Year Ended December 31,	2007	2006	2005
SCE	**$ 87**	$ 85	$ 127
EMG	**8**	48	9
Edison International Consolidated	**$ 95**	$ 133	$ 136

SCE's other nonoperating income decreased $42 million in 2006. The 2006 decrease was mainly due to the recognition of approximately $45 million in incentives related to demand-side management and energy efficiency performance recorded in 2005. In addition, SCE recorded shareholder incentives of $6 million and $23 million in 2006 and 2005, respectively (see "SCE: Regulatory Matters — Current Regulatory Developments — FERC Refund Proceedings" for further discussion).

EMG's other nonoperating income decreased $40 million in 2007 and increased $39 million in 2006. The 2007 and 2006 variances are due to estimated insurance recoveries related to EMG's Homer City Unit 3 outage claims on property and business interruption insurance policies of approximately $3 million recorded during 2007 compared to $11 million recorded in 2006. The 2007 and 2006 variances also reflect an $8 million gain related to the receipt of shares from Mirant Corporation from settlement of a claim and a $4 million gain resulting from EMG's sale of 25% of its ownership interest in the San Juan Mesa wind project to Citi Renewable Investments I LLC, both recognized in the first quarter of 2006. In addition, the 2006 increase reflects the recognition of a $19 million gain in 2006 on the sale of certain Edison Capital's investments, including Edison Capital's interest in an affordable housing project.

Interest Expense – Net of Amounts Capitalized

In millions For the Year Ended December 31,	2007	2006	2005
SCE	**$ 430**	$ 400	$ 360
EMG	**320**	403	430
Edison International (parent) and other	**2**	4	4
Edison International Consolidated	**$ 752**	$ 807	$ 794

SCE's interest expense – net of amounts capitalized increased $30 million in 2007 and increased $40 million in 2006. The 2007 increase was mainly due to higher interest expense on balancing account overcollections in 2007, as compared to 2006. The increase was also due to higher interest expense on long-term debt resulting from higher balances outstanding during 2007, as compared to 2006. The 2006 increase was 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, compared to 2005.

EMG's interest expense – net of amounts capitalized decreased $83 million in 2007 and decreased $27 million in 2006. The 2007 decrease was primarily attributable to MEHC's redemption in full of its senior secured notes in June 2007, and an increase in capitalized interest due to wind projects under construction. The variances are also attributable to $2.7 billion of new debt entered into by EME as part of its refinancing activities in May 2007 (See "EMG: Liquidity — EMG Refinancing Developments"). The 2006 decrease was mainly due to lower interest rates resulting from MEHC's refinancing in June 2006.

Other Nonoperating Deductions

In millions For the Year Ended December 31,	2007	2006	2005
SCE	**$ 45**	$ 60	$ 65
EMG	**—**	3	2
Edison International Consolidated	**$ 45**	$ 63	$ 67

SCE's other nonoperating deductions decreased $15 million in 2007 and decreased $5 million in 2006. The 2007 decrease was mainly due to a penalty accrual of $23 million under the customer satisfaction performance mechanism recognized in 2006.

Impairment Loss on Equity Method Investment

In 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 in 2005.

Loss on Early Extinguishment of Debt

Loss on early extinguishment of debt in 2007 primarily consisted of $241 million relating to the early repayment of EME's 7.73% senior notes due June 15, 2009, Midwest Generation's 8.75% second priority senior secured notes due May 1, 2034, and MEHC's 13.5% senior secured notes due July 15, 2008.

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,	2007	2006	2005
SCE	**$ 337**	$ 438	$ 292
EMG	**171**	154	162
Edison International (parent) and other	**(16)**	(10)	3
Edison International Consolidated	**$ 492**	$ 582	$ 457

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 from continuing operations in 2007 was 30.9%. The decreased effective tax rate was caused primarily by reductions made to the income tax reserve to reflect progress in an administrative appeals process with the IRS related to SCE's income tax treatment of costs associated with environmental remediation, reductions made to the income tax reserves to reflect settlement of a state tax issue related to the April 2007 State Notice of Proposed Adjustment discussed below and due to production and low income housing credits at EMG.

The effective tax rate of 35.0% in 2006 reflected an SCE settlement with the California Franchise Tax Board regarding a state apportionment issue (see "Other Developments — Federal and State Income Taxes") and production and low income housing tax credits at EMG, which served to reduce the effective tax rate, but this was partially offset by additional tax reserve accruals at SCE. The lower effective tax rate of 29.2% in 2005 was primarily due to the favorable resolution of the 1991 – 1993 IRS audit cycle, adjustments made to the tax reserve to reflect the impact of new IRS regulations and the favorable settlement of other federal and state tax audit issues at SCE and EMG.,

Edison International and its subsidiaries had California net operating loss carryforwards with expirations dates beginning in 2012 of $54 million and $69 million at December 31, 2007 and 2006, respectively.

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 income (loss) from discontinued operations was $(2) million, $97 million, and $30 million in 2007, 2006, and 2005, respectively. Edison International's earnings from discontinued operations of $97 million in 2006 were mainly attributable to distributions from the Lakeland project and other adjustments related to the disposition of some of EME'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.

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.

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,**	**2007**	**2006**	**2005**
Continuing operations	**$ 3,195**	$ 3,474	$ 2,225
Discontinued operations	**(2)**	94	22
	$ 3,193	$ 3,568	$ 2,247

Cash provided by operating activities from continuing operations decreased $279 million in 2007, compared to 2006. The 2007 change reflects an increase of $48 million in required margin and collateral deposits in 2007 for EMG's hedging and trading activities, compared to a decrease of $625 million in 2006. This change resulted from an increase in forward market prices in 2007 compared to 2006. The 2007 change also reflects a decrease in revenue collected from SCE's customers primarily due to lower rates in 2007, compared to 2006. On February 14, 2007, SCE reduced its system average rate mainly as the result of estimated lower natural gas prices in 2007, the refund of overcollections in the ERRA balancing account that occurred in 2006 and the impact of the redesign of SCE's tiered rate structure in 2007 (see "SCE: Regulatory Matters—Current Regulatory Developments—Impact of Regulatory Matters on Customer Rates" for further discussion). Loss on early extinguishment of debt in 2007 primarily consisted of $241 million relating to the early repayment of EME's 7.73% senior notes due June 15, 2009, Midwest Generation's 8.75% second priority senior secured notes due May 1, 2034, and MEHC's 13.5% senior secured notes due July 15, 2008. The 2007 change was also due to the timing of cash receipts and disbursements related to working capital items including lower income taxes paid in 2007, compared to 2006.

The 2006 increase was mainly due to an increase in cash collected from SCE's customers due to increased 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 $625 million in required margin and collateral deposits in 2006 mainly for EME's hedging and trading activities, compared to an increase of $656 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.

Cash provided by operating activities from discontinued operations decreased $96 million in 2007 compared to 2006. The 2007 decrease reflects higher distributions received in 2006, compared to 2007, from EME's Lakeland power project. See "Discontinued Operations" for more information regarding these distributions. 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 EME's Lakeland power project. See "Discontinued Operations" for more information regarding these distributions.

Cash Flows from Financing Activities

Net cash used by financing activities:

In millions **For the Year Ended December 31,**	**2007**	**2006**	**2005**
Continuing operations	**$ (877)**	$ (703)	$ (1,244)

Cash used by financing activities from continuing operations mainly consisted of long-term debt issuances (payments) at SCE and EMG and dividends paid by Edison International to its common shareholders.

Financing activities in 2007 were as follows:

- During 2007, SCE's net issuance of short-term debt was $500 million;
- In May 2007, EME issued $2.7 billion of senior notes, which was mostly used to repay $587 million of EME's outstanding senior notes, repay $1 billion of Midwest Generation's second priority senior secured notes, fund a dividend to MEHC which purchased approximately $796 million of its 13.5% senior secured notes, and repay $328 million of Midwest Generation's senior secured term loan facility. In addition, EME and MEHC paid tender premiums and financing costs of $239 million related to the debt refinancing;
- During the fourth quarter of 2007, SCE repaid the remaining outstanding balance of its rate reduction bonds in the amount of $246 million; and
- Financing activities in 2007 include dividend payments of $283 million paid by Edison International to its common shareholders.

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 EMG, as follows:

- 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 in part 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 2,000,000 shares of 6% Series C preference stock (noncumulative, $100 liquidation value) and received net proceeds of approximately $197 million;
- In April 2006, SCE issued $331 million of tax-exempt bonds which consisted of $196 million of 4.10% bonds which are subject to remarketing in April 2013 and $135 million of 4.25% bonds which are subject to remarketing in November 2016. The proceeds from this issuance were used to call and redeem $196 million of tax-exempt bonds due February 2008 and $135 million of tax-exempt bonds due March 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 $1 billion of EME's outstanding senior notes and to pay $139 million 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; and
- Financing activities in 2006 also included dividend payments of $352 million paid by Edison International to its common shareholders.

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

- 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, EME repaid $150 million of 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 7.23% Series $100 cumulative preferred stock, and approximately $64 million of the proceeds was used to redeem all the outstanding shares of its 6.05% Series $100 cumulative preferred stock;
- In April 2005, EME 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;
- In September 2005, SCE issued 2,000,000 shares of Series B preference stock (noncumulative, $100 liquidation value) and received net proceeds of approximately $197 million; and

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

Cash Flows from Investing Activities

Net cash used by investing activities:

In millions **For the Year Ended December 31,**	**2007**	**2006**	**2005**
Continuing operations	**$ (2,670)**	$ (2,963)	$ (1,804)
Discontinued operations	**—**	—	5
	$ (2,670)	$ (2,963)	$ (1,799)

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

Investing activities in 2007 reflect $2.28 billion in capital expenditures at SCE, primarily for transmission and distribution assets, including approximately $123 million for nuclear fuel acquisitions, and $540 million in capital expenditures at EMG. Investing activities also include higher turbine deposits (net of deposit refunds of $112 million) at EMG, net maturities and sales of short term investments of $477 million, $22 million towards the purchase price of new wind projects, $24 million to acquire a 1% interest in twelve designated projects and the option to purchase the remaining 99%, and $11 million in payments made towards the purchase price of EMG's Wildorado wind project during the second quarter of 2007.

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 EMG. In addition, investing activities include net purchases of marketable securities of $375 million at EMG as well as the receipt of $43 million in proceeds from the sale of 25% of EME's ownership interest in the San Juan Mesa wind project. EMG also paid $18 million towards the purchase price of the Wildorado wind project during the first quarter of 2006.

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 EMG. 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 EMG.

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, by and between EME and IPM for approximately $20 million. EME recorded an impairment charge of approximately $5 million during the fourth quarter of 2004 related to the planned disposition of this investment. 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 CBK project pursuant to a Purchase Agreement, dated November 5, 2004, by and between EME and Corporacion IMPSA S.A. 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.

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 the project's 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 £5 million (approximately $10 million) in 2007. The after-tax income attributable to the Lakeland project was $6 million, $85 million and $24 million for 2007, 2006 and 2005, respectively. 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 2007, 2006 or 2005.The pre-tax earnings (loss) from discontinued operations was $3 million in 2007, $118 million in 2006 and $(20) million in 2005. The pre-tax loss from discontinued operations in 2005 included a $9 million gain on sale before taxes.

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, 2007 and 2006.

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 Wildorado Wind, L.P., 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. This project started construction in April 2006 and commenced commercial operation during April 2007. 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 property, plant and equipment 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 $156.5 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 property, plant and equipment 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.

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.

CRITICAL ACCOUNTING ESTIMATES AND POLICIES

The accounting policies described below are viewed by management as critical because their application is the most relevant and material to Edison International's results of operations and financial position and these policies require the use of material judgments and estimates. Many of the critical accounting estimates and policies discussed below generally do not impact SCE's earnings since SCE applies accounting principles for rate-regulated enterprises. However, these critical accounting estimates and policies 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 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, 2007, the consolidated balance sheets included regulatory assets of $2.9 billion and regulatory liabilities of $4.5 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 remaining gain or loss on the derivative instrument, if any, is recognized currently in earnings.

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. 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.

Determining whether or not Edison International's transactions meet the definition of a derivative instrument requires management to exercise significant judgment, including determining whether the transaction has one or more underlyings, one or more notional amounts, requires no initial net investment, and whether the terms require or permit net settlement. If it is determined that the transaction meets the definition of a derivative instrument, additional management judgment is exercised in determining whether the normal sales and purchases exception applies or whether individual transactions qualify for hedge accounting treatment, if elected.

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 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 under accounting rules is recorded on the balance sheet at fair value, based on financial models. 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.

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. 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, or (2) qualify as normal purchases and sales and are, therefore, recorded on an accrual basis.

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."

For those transactions that meet the definition of a derivative instrument, did not qualify for the normal sales and purchase exception, and hedge accounting was not elected, determining the fair value requires management to exercise significant judgment. Edison International makes estimates and assumptions concerning future commodity prices, load requirements and interest rates in determining the fair value of a derivative instrument. The fair value of a derivative is susceptible to significant change resulting from a number of factors, including volatility of commodity prices, credit 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 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. FIN 48 clarifies the accounting for uncertain tax positions. FIN 48 (adopted on January 1, 2007) requires an enterprise 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. Management continues to monitor and assess new income tax developments.

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.

Investment tax credits are deferred and amortized over the lives of the related properties. Energy tax credits are also deferred and amortized over the term of the power purchase agreement of the respective project while production tax credits are recognized when earned. EME's investments in wind-powered electric generation projects qualify for federal production tax credits under Section 45 of the Internal Revenue Code. Such credits are allowable for production during the 10-year period after a qualifying wind energy facility is placed into service. Certain of EME's wind projects also qualify for state tax credits which are accounted for similarly as federal production tax credits.

Accounting for tax obligations requires judgments, including estimating reserves for potential adverse outcomes regarding tax positions that have been taken. Management uses judgment in determination of whether the evidence indicates it is more likely than not, based solely on the technical merits, that the position will be sustained on audit. 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. Income tax expense includes the current tax liability from operations and the change in deferred income taxes during the year. Interest expense and penalties associated with income taxes are reflected in the caption "Income tax expense" on the consolidated statements of income. 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"). 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 sheets. 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 recognition of the straight-line depreciation on the leased assets as well as the interest component of the financings which is weighted more heavily toward the early years of the obligations. The difference in expense recognition would not affect EME's cash flows under these transactions. See "Off-Balance Sheet Transactions."

Edison Capital has entered into lease transactions, as lessor, related to various power generation, electric transmission and distribution, transportation and telecommunications assets. All of the debt under Edison Capital's leveraged leases is nonrecourse and is not recorded on Edison International's balance sheets 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 sheets. 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 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.

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, EME recorded impairment charges of $55 million related to specific assets included in continuing operations. See "Results of Operations and Historical Cash Flow Analysis — Results of Operations — Operating Expenses — Impairment Loss on Equity Method Investment 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, which effective January 2007, receive contributions of approximately $46 million per year. As of December 31, 2007, the decommissioning trust balance was $3.4 billion. Contributions to the decommissioning trusts are reviewed every three years by the CPUC. The contributions are determined based on an analysis of the current value of trust assets and long-term forecasts of cost escalation, the estimate and timing of decommissioning costs, 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.

SCE's nuclear decommissioning trusts are accounted for in accordance with SFAS No. 115, Accounting for Certain Investments in Debt and Equity Securities, and due to regulatory recovery of SCE's nuclear decommissioning expense, rate-making accounting treatment is applied to all nuclear decommissioning trust activities in accordance with SFAS No. 71. As a result, nuclear decommissioning activities do not affect SCE's earnings.

SCE's nuclear decommissioning trust investments are classified as available-for-sale. SCE has debt and equity investments for the nuclear decommissioning trust funds. Contributions, earnings, and realized gains and losses (including other than temporary impairments) are recognized as revenue, and due to regulatory accounting treatment, also represent an increase in the nuclear obligation and increase decommissioning expense. Unrealized gains and losses on decommissioning trust funds increase or decrease the trust asset and the related regulatory asset or liability and have no impact on revenue or decommissioning expense. SCE reviews each security for other-than-temporary impairment losses on the last day of the current month and the last day of the prior month. If the fair value on both days is less than the cost of 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.

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 $89 million as of December 31, 2007 is recorded as an ARO liability.

Pensions and Postretirement Benefits Other than Pensions

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 normally offset through other comprehensive income (loss). Edison International adopted SFAS No. 158 as of December 31, 2006. In accordance with SFAS No. 71, 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. 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.

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, 2007 measurement date, Edison International used a discount rate of 6.25% 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% rate of return on plan assets above is determined on an after-tax basis. Actual time-weighted, annualized returns on the pension plan assets were 8.8%, 14.7% and 9.6% for the one-year, five-year and ten-year periods ended December 31, 2007, respectively. Actual time-weighted, annualized returns on the PBOP plan assets were 6.9%, 12.6%, and 6.8% 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 96% of its assets held in trusts, at December 31, 2007. 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. 87, Employers' Accounting for Pensions, and SFAS No. 158 is accumulated as a regulatory asset or liability, and will, over time, be recovered from or returned to customers. As of December 31, 2007, this cumulative difference amounted to a regulatory liability of $75 million, meaning that the rate-making method has recognized $75 million more in expense than the accounting method since implementation of SFAS No. 87 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, 2007, Edison International's PBOP plans had a $2.3 billion benefit obligation. Total expense for these plans was $57 million for 2007. The health care cost trend rate is 9.25% for 2007, gradually declining to 5.0% for 2015 and beyond. Increasing the health care cost trend rate by one percentage point would increase the accumulated obligation as of December 31, 2007 by $273 million and annual aggregate service and interest costs by $20 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated obligation as of December 31, 2007 by $243 million and annual aggregate service and interest costs by $18 million.

NEW ACCOUNTING PRONOUNCEMENTS

Accounting Pronouncements Adopted

In July 2006, the FASB issued FIN 48 which clarifies the accounting for uncertain tax positions. FIN 48 requires an enterprise 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 adopted FIN 48 effective

January 1, 2007. Implementation of FIN 48 resulted in a cumulative-effect adjustment that increased retained earnings by $250 million upon adoption. 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 in the timing of cash flows related to income taxes generated by a leverage lease transaction (FSP FAS 13-2). Edison International adopted FSP FAS 13-2 effective January 1, 2007. The adoption did not have any impact on Edison International's consolidated financial statements.

Accounting Pronouncements Not Yet Adopted

In April 2007, the FASB issued FIN 39-1. FIN 39-1 amends paragraph 3 of FIN No. 39 to replace the terms conditional contracts and exchange contracts with the term derivative instruments as defined in SFAS No. 133. FIN 39-1 also states that under master netting arrangements if collateral is based on fair value, then it must be netted with the fair value of derivative assets/liabilities if an entity qualified and elected the option to net those amounts. Edison International will adopt FIN 39-1 in the first quarter of 2008. The adoption is expected to result in netting a portion of margin and cash collateral deposits with derivative liabilities on Edison International's consolidated balance sheets, but will have no impact on Edison International's consolidated statements of income.

In February 2007, the FASB issued SFAS No. 159, which provides an option to report eligible financial assets and liabilities at fair value, with changes in fair value recognized in earnings. Edison International will adopt this pronouncement in the first quarter of 2008 and may elect to report certain financial assets and liabilities at fair value. The adoption is not expected to result in a cumulative-effect adjustment to retained earnings.

In September 2006, the FASB issued SFAS No. 157, which 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 in the first quarter of 2008. The adoption is not expected to result in any retrospective adjustments to its financial statements. The accounting requirements for employers' pension and other postretirement benefit plans is effective at the end of 2008 which is the next measurement date for these benefit plans. The effective date will be January 1, 2009 for asset retirement obligations and other nonfinancial liabilities which are not measured or disclosed on a recurring basis (at least annually).

In December 2007, the FASB issued SFAS No. 141(R), which establishes principles and requirements for how the acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date fair value. SFAS No. 141(R) determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. SFAS No. 141(R) applies prospectively to business combinations for which the acquisition date is on or after fiscal years beginning on or after January 1, 2009.

In December 2007, the FASB issued SFAS No. 160, which requires an entity to clearly identify and present ownership interests in subsidiaries held by parties other than the entity in the consolidated financial statements within the equity section but separate from the entity's equity. It also requires the amount of consolidated net income attributable to the parent and to the noncontrolling interest to be clearly identified and presented on the face of the consolidated statement of income; changes in ownership interest be accounted for similarly as equity transactions; and, when a subsidiary is deconsolidated, any retained noncontrolling equity investment in the former subsidiary and the gain or loss on the deconsolidation of the subsidiary be measured at fair value. Edison International will adopt SFAS No. 160 on January 1, 2009 and is currently evaluating the impact of adopting SFAS No. 160 on its consolidated financial statements. In accordance with this standard, Edison International will reclassify minority interest to a component of shareholder's equity (at December 31, 2007 this amount was $295 million).

COMMITMENTS, GUARANTEES AND INDEMNITIES

Edison International's commitments as of December 31, 2007, for the years 2008 through 2012 and thereafter are estimated below:

In millions	2008	2009	2010	2011	2012	Thereafter
Long-term debt maturities and interest[1]	$ 574	$ 724	$ 841	$ 538	$ 539	$ 14,371
Fuel supply contract payments	541	407	223	77	73	243
Gas and coal transportation payments	253	168	172	8	8	43
Purchased-power capacity payments	410	324	294	290	339	1,152
Operating lease obligations	980	1,056	1,001	765	598	3,897
Capital lease obligations	4	3	4	1	1	7
Turbine commitments	484	540	49	—	—	—
Capital improvements	249	—	—	—	—	—
Other commitments	34	28	29	18	10	27
Employee benefit plans contributions[2]	110	—	—	—	—	—
Total[3]	$ 3,639	$ 3,250	$ 2,613	$ 1,697	$ 1,568	$ 19,740

(1) Amount includes scheduled principal payments for debt outstanding as of December 31, 2007 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 EME and SCE are not available beyond 2008.

(3) At December 31, 2007, Edison International had a total net liability recorded for uncertain tax positions of $374 million, which is excluded from the table. Edison International cannot make reliable estimates of the cash flows by period due to uncertainty surrounding the timing of resolving these open tax issues with the IRS.

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, 2007, Midwest Generation and EME Homer City had fuel purchase commitments with various third-party suppliers. 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 — Commodity Price Risk — Coal Price Risk."

Gas and Coal Transportation

At December 31, 2007, 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 10 years.

At December 31, 2007, EME's subsidiaries had contractual commitments for the transport of coal to their respective facilities. Midwest Generation's primary contract is with Union Pacific Railroad (and various delivering 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.

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 above). 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 2006, SCE modified 62 power contracts. No contracts were modified in 2007. 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 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 lease on a straight-line basis. At December 31, 2007, the net liability was $59 million. At December 31, 2007, SCE had 67 power contracts classified as operating leases. Operating lease expense for power purchases was $297 million in 2007, $188 million in 2006, and $68 million in 2005. In addition, SCE executed a power purchase contract in late 2005 and an additional power purchase contract in June 2007 which met the requirements for capital leases. These capital leases have a net commitment of $20 million at December 31, 2007 and $13 million at December 31, 2006. SCE's capital lease executory costs and interest expense was $2 million in 2007 and $3 million in 2006.

At December 31, 2007, 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 $337 million in 2008, $336 million in 2009, $325 million in 2010, $311 million in 2011, $311 million in 2012, and the minimum lease payments due after 2012 are $2.3 billion. For further discussion, see "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, 2007, EME had entered into agreements with vendors securing 483 wind turbines (1,076 MW) with remaining commitments of $481 million in 2008, $540 million in 2009 and $49 million in 2010. At December 31, 2007 and 2006, EME had recorded wind turbine deposits of $189 million and $143 million, respectively, included in other long-term assets in its consolidated balance sheets. In addition, EME had 30 wind turbines (90 MW) in temporary storage to be used for future wind projects with remaining commitments of $3 million in 2008. At December 31, 2007, EME had recorded $84 million related to these wind turbines included in other long-term assets in its consolidated balance sheets.

Capital Improvements

At December 31, 2007, EME's subsidiaries had firm commitments for capital and construction expenditures. The majority of these expenditures relate to the construction of wind 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 $53 million through 2016 (approximately $6 million per year).

As of December 31, 2007, standby letters of credit aggregated to $97 million and were scheduled to expire as follows: $89 million in 2008 and $8 million in 2009.

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 continues to have obligations under the tax indemnity agreement with the former lease equity investor.

Indemnities Provided as Part of the 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 had an initial five-year term with an automatic renewal provision for subsequent one-year terms (subject to the right of either party to terminate); pursuant to the automatic renewal provision, it has been extended until February 2009. 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 207 cases for which Midwest Generation was potentially liable and that had not been settled and dismissed at December 31, 2007. Midwest Generation had recorded a $54 million liability at December 31, 2007 related to this matter.

Midwest Generation engaged an independent actuary in 2004 to complete an estimate of future losses. Based on the actuary's analysis, Midwest Generation recorded an undiscounted liability for its indemnity for future asbestos claims through 2045. During the fourth quarter of 2007, the actuary report was updated and the liability reduced by $9 million. In calculating future losses, the actuary made various assumptions, including but not limited to, the settlement of future claims under the supplemental agreement with Commonwealth Edison as described above, the distribution of exposure sites, and that no asbestos claims will be filed after 2044.

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 the 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, 2007, EME had recorded a liability of $101 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. At December 31, 2007, EME had recorded a liability of $12 million related to these matters.

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. The obligations under this indemnification agreement as of December 31, 2007, if payment were required, would be $73 million. EME has not recorded a liability related to this indemnity.

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.

Mountainview Filter Cake Indemnity

Mountainview owns and operates a power plant in Redlands, California. The plant utilizes water from on-site groundwater wells and City of Redlands (city) recycled water for cooling purposes. Unrelated to the operation of the plant, this water contains perchlorate. The pumping of the water removes perchlorate from the aquifer beneath the plant and concentrates it in the plant's wastewater treatment "filter cake." Use of this impacted groundwater for cooling purposes was mandated by Mountainview's California Energy Commission permit. Mountainview has indemnified the city for cleanup or associated actions related to groundwater contaminated by perchlorate due to the disposal of filter cake at the city's solid waste landfill. The obligations under this agreement are not limited to a specific time period or subject to a maximum liability. SCE has not recorded a liability related to this guarantee.

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 EMG. 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 EME, EME's obligations to one of its subsidiaries, and leveraged leases at Edison Capital.

Investments Accounted for under the Equity Method

EMG has a number of investments in power projects and partnership investments in which it does not have operational control or significant voting rights that are accounted for under the equity method. Under the equity method, the project assets and related liabilities are not consolidated in Edison International's consolidated balance sheet. Rather, Edison International's financial statements reflect its investment in each entity and it records only its proportionate ownership share of net income or loss. These investments are of three principal categories.

Historically, EME has invested in qualifying facilities, 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 EPAct 2005, these regulations limited EME's ownership interest in qualifying facilities to no more than 50% due to EME's affiliation with SCE, a public utility. For this reason, EME owns a number of domestic energy projects through partnerships in which it has a 50% or less ownership interest.

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, 2007, entities which EME has accounted for under the equity method had indebtedness of $359 million, of which $159 million is proportionate to EME's ownership interest in these projects.

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, 2007, 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, 2007, entities that Edison Capital has accounted for under the equity method had indebtedness of approximately $1.6 billion, of which approximately $526 million is proportionate to Edison Capital's ownership interest in these projects. Substantially all of this debt is nonrecourse to Edison Capital.

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 Indemnities — Operating and Capital Leases." 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 $54 million, $61 million and $72 million in 2007, 2006 and 2005, 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:

Power Station(s)	Acquisition Price	Equity Investor	Original Equity Investment in Owner/Lessor	Amount of Lessor Debt at December 31, 2007	Maturity Date of Lessor Debt
			(in millions)		
Powerton/Joliet	$ 1,367	PSEG/ Citigroup, Inc.	$ 238	$ 175.5 Series A	2009
				679.1 Series B	2016
Homer City	1,591	GECC/ Metropolitan Life Insurance Company(1)	798	$ 255.0 Series A	2019
				514.1 Series B	2026

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 (GAAP), EME records rent expense on a levelized basis over the terms of the respective leases. The following table summarizes the lease payments and rent expense for the three years ended December 31, 2007.

In millions **Years ended December 31,**	**2007**	**2006**	**2005**
Cash payments under plant operating leases			
Powerton and Joliet facilities	**$ 185**	$ 185	$ 141
Homer City facilities	**151**	152	152
Total cash payments under plant operating leases	**$ 336**	$ 337	$ 293
Rent expense			
Powerton and Joliet facilities	**$ 75**	$ 75	$ 75
Homer City facilities	**102**	102	102
Total rent expense	**$ 177**	$ 177	$ 177

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, 2007 and 2006, prepaid rent on these leases was $716 million and $556 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 Indemnities — Operating and Capital Leases."

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 **Years ending December 31,**	**Principal Amount**	**Interest Amount**	**Total**
2008	$ 4	$ 112	$ 116
2009	5	112	117
2010	5	112	117
2011	9	111	120
2012	11	111	122
Thereafter	1,323	290	1,613
Total	**$ 1,357**	**$ 848**	**$ 2,205**

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.

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, 2007, Edison Capital had net investments, before deferred taxes, of $2.6 billion in its leveraged leases, with nonrecourse debt in the amount of $5.2 billion.

OTHER DEVELOPMENTS

Environmental Matters

The operating subsidiaries 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 subsidiaries are in substantial compliance with existing environmental regulatory requirements. However, the US EPA has issued a NOV to Midwest Generation and Commonwealth Edison, the former owner of Midwest Generation's coal-fired power plants, alleging violations of the CAA and certain opacity and particulate matter standards. For information on the US EPA NOV issued to Midwest Generation, See "EMG: Other Developments — Midwest Generation Potential Environmental Proceeding" above.

The domestic power plants owned or operated by Edison International's operating subsidiaries, 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 NOx 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: 2008 – $539 million; 2009 – $511 million; 2010 – $741 million; 2011 – $491 million; and 2012 – $532 million. The projected environmental capital expenditures are mainly for undergrounding certain transmission and distribution lines at SCE and upgrading environmental controls at EME.

Climate Change

Federal Legislative Initiatives

Currently a number of bills are proposed or under discussion in Congress to mandate reductions of GHG emissions. At this point, it cannot be determined whether any of these proposals will be enacted into law or to estimate their potential effect on the operations of Edison International's subsidiaries. The ultimate outcome of the debate about GHG emission regulation on the federal level could have a significant economic effect on the operations of Edison International's subsidiaries. Any legal obligation that would require a substantial reduction in emissions of carbon dioxide or would impose additional costs or charge for the emission of carbon dioxide could have a materially adverse effect on operations.

Edison International supports a national regulatory program for GHG emission reduction that is market-based, equitable and comprehensive, through which all sources of GHG emissions are regulated and all certifiable means of reducing and offsetting such emissions are recognized. This program should be long-term, and should establish technologically realistic GHG emission reduction targets.

Litigation Developments

Significant climate change litigation, raising issues that may affect the timing and scope of future GHG emission regulation, has been brought by a variety of public and private parties in the past several years. Although decisions were handed down in several of the major cases in 2007, it is too early to determine how the courts will respond to every situation. To date, the cases in which plaintiffs have sought damages or equitable relief directly from power companies and other defendants have been dismissed, either because the courts have determined that a judicial decision would impermissibly intrude on the powers of the legislative and executive branches to regulate and, as applicable, enter into foreign compacts concerning GHG emissions or because of the absence of evidence linking any individual defendant's GHG emissions to any harm allegedly caused by climate change. For example, Connecticut v. AEP, a case brought in 2004 by several states and environmental organizations alleging that several electric utility corporations are jointly and severally liable under a theory of public nuisance for power plants owed and operated by these companies or their subsidiaries, was dismissed and is currently on appeal before the United States Court of Appeals for the Second Circuit. In another case brought in April 2006, private citizens filed a complaint in federal court in Mississippi against numerous defendants, including Edison International and several electric utilities, arguing that emissions from the defendants' facilities contributed to climate change and seeking monetary damages related to the 2005 hurricane season. In July 2006, Edison International was dismissed from the case because of its status as a holding company. In August 2007, the court dismissed the case entirely. The plaintiffs have appealed this dismissal in the Fifth Circuit Court of Appeals. On the other hand, plaintiffs thus far have been generally successful in cases in which they have sought to compel federal or state agencies to regulate GHG emissions.

Responses to Energy Demands and Future GHG Emission Constraints

Irrespective of the outcome of federal legislative deliberations, Edison International believes that substantial limitations on GHG emissions are inevitable, through increased costs, mandatory emission limits or other mechanisms, and that demand for energy from renewable sources will also continue to increase. As a result, SCE and EME are utilizing their experience in developing and managing a variety of energy generation systems to create a generation profile, using sources such as wind, solar, geothermal, biomass and small hydro plants, that will be adaptable to a variety of regulatory and energy use environments. SCE leads the nation in renewable power delivery. Its renewable portfolio currently consists of: 1,021 MW from wind, 892 MW from geothermal, 354 MW from solar, 221 MW from biomass, 128 MW from SCE-owned small hydro (six of the 36 hydroelectric projects that SCE currently operates have generated power for more than a century), and 95 MW from independently owned small hydro.

SCE has developed and promoted several energy efficiency and demand response initiatives in the residential market, including an ongoing meter replacement program to help reduce peak energy demand; a rebate program to encourage customers invest in more efficient appliances; subsidies for purchases of energy efficient lighting products; appliance recycling programs; widely publicized tips to our customers for saving energy; and a voluntary demand response program which offers customers financial incentives to reduce their electricity use. SCE is also replacing its electro-mechanical grid control systems with computerized devices that allow more effective grid management.

During 2007, EME participated in the early development of new clean coal generation projects. Due to the projected increase in the capital costs of these projects and the lack of a regulatory framework addressing CO_2 sequestration, EME is not actively developing specific new clean coal generation or gasification projects at this time, but intends to continue to evaluate the feasibility of these projects in the future. During 2007, EME also assessed the possibility of pursuing new solar projects in locations where power purchase agreements may support investment. EME plans to expand its renewable project development efforts in 2008 to include solar projects in addition to wind projects.

State Specific Legislative Initiatives

SCE and EME are evaluating the CARB's reporting regulations adopted December 2007 pursuant to AB 32 to assess the total cost of compliance.

On February 8, 2008, the CPUC and CEC recommended, in a proposed decision, that CARB adopt a mix of direct mandatory/regulatory requirements and a cap-and-trade system for the energy sectors. The proposed decision's requirements include: all retail electricity providers should be required to provide all cost-effective energy efficiency programs and renewable energy delivery beyond the level of 20% of their retail sales to their customers; a multi-sector cap-and-trade program should be developed for California that includes the electricity sector; the CARB should designate deliverers of electricity to the California grid as the entities responsible for compliance with the AB 32 requirements; at least some portion of the emission allowances available to the electricity sector for the cap-and-trade program should be auctioned. An integral part of this auction recommendation is that at least a portion of the proceeds from the auctioning of allowances for the electricity sector should be used in ways that benefit electricity consumers in California, such as to augment investments in energy efficiency and renewable energy or to provide customer bill relief. SCE is currently evaluating the proposed decision.

Other California legislative proposals or initiatives addressing climate change, including requirements for procurement of power from renewable resources, if adopted, could have a material impact on SCE's business.

Air Quality Regulation

Clean Air Interstate Rule

Illinois

Under its agreement with the Illinois EPA, 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 have been previously estimated (in 2006 dollars) to be approximately $450 million. See further discussion below regarding updating the estimated costs of completing environmental improvements.

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 the units 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 the third phase. Additional capital expenditures during the third phase of the plan have been previously estimated (in 2006 dollars) 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.

Midwest Generation is in the process of completing preliminary engineering and permitting work and is in the process of selecting a final engineering, procurement and construction contractor for the environmental improvements at the Powerton Station. It is expected that detailed scoping necessary to update the cost estimates at the Powerton Station, and then using such information to update the cost estimates for the environmental improvements included in Phases II and III above will be completed in 2008. Until such information is completed, currently expected during the fourth quarter of 2008, the capital expenditures estimates may vary substantially for the reasons described above.

Pennsylvania

On December 18, 2007, the Pennsylvania Environmental Quality Board approved the Pennsylvania CAIR. This rule has been submitted to the USEPA for approval as part of the Pennsylvania SIP. The Pennsylvania CAIR is substantively similar to the CAIR. EME Homer City will be subject to the federal CAIR rule during 2009 and expects to be able to comply with the NO_x requirement using its existing selective catalytic reduction system. The Pennsylvania CAIR, including both NO_x and SO_2 limits, is expected to become effective in 2010. EME Homer City expects to comply with Pennsylvania CAIR through the continued operation of its scrubber on Unit 3 to reduce SO_2 emissions and the purchase of SO_2 allowances.

Mercury Regulation

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. The Pennsylvania CAMR SIP, which embodies PADEP's mercury regulation, was pending approval by the US EPA prior to the February 8, 2008, decision vacating the federal CAMR.

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 and coal washing on the other two units. In order to meet reductions in emissions by the 2015 deadline, it is likely that additional environmental control equipment will need to be installed. If additional environmental equipment is required in the form of flue gas desulfurization equipment, EME would need to make commitments during 2011 or 2012. EME 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.

New Mexico

Due to the February 8, 2008 D.C. Circuit Court decision vacating the CAMR, Arizona Public Service Company, the operator of Four Corners, will monitor the developments to determine the type and timing of any necessary equipment installation.

Regional Haze

The goal of the regional haze regulations is to restore visibility in mandatory federal Class I areas, such as national parks and wilderness areas, to natural background conditions by 2064. Sources such as power plants that are reasonably anticipated to contribute to visibility impairment in Class I areas may be required to install Best Available Retrofit Technology (also know as BART) or implement other control strategies to meet regional haze control requirements. It is possible that sources subject to the CAIR will be able to satisfy their obligations under the regional haze regulations through compliance with the CAIR. However, until the SIPs are revised, EME cannot predict whether it will be required to install BART or implement other control strategies, and cannot identify the financial impacts of any additional control requirements.

Pennsylvania

In Pennsylvania, the PADEP considers the CAIR to meet the BART requirements, and the Homer City facilities are only required to consider reductions in emissions of suspended particulate matter (PM10), which at this time are being evaluated by the state.

New Mexico

The Regional office of the US EPA (EPA Region 9) requested that Arizona Public Service Company perform a BART analysis for Four Corners. This analysis was completed and submitted it to the US EPA on January 30, 2008. The EPA Region 9 will review Arizona Public Service Company's submission and determine what constitutes BART for Four Corners. Once Arizona Public Service Company receives the EPA Region 9's final determination, it will have five years to complete the installation of the equipment and to achieve the emission limits established by the EPA Region 9. Until the EPA Region 9 makes a final determination on this matter, SCE cannot accurately estimate the expenditures that may be required. SCE also cannot predict whether the relevant environmental agencies will agree with its BART recommendations or, if the agencies disagree with our recommendations, the nature of the BART controls the agencies may ultimately mandate and the resulting financial or operational impact.

Illinois

The CPS, discussed above in "— Clean Air Interstate Rule — Illinois," addresses emissions reductions at BART affected sources.

New Source Review Requirements

Prior to EME's purchase of the Homer City facilities, the US EPA requested information under Section 114 of the CAA from the prior owners of the plant concerning physical changes at the plant. This request was part of the US EPA's industry-wide investigation of compliance by coal-fired plants with the CAA NSR requirements. On February 21, 2003, Midwest Generation received a request for information under Section 114 regarding past operations, maintenance and physical changes at the Illinois plants from the US EPA. On July 28, 2003, Commonwealth Edison received a substantially similar request for information from the US EPA related to the same plants. In a request dated February 1, 2005, the US EPA submitted a request for additional information to Midwest Generation. Midwest Generation has provided responses to these requests. On August 3, 2007, Midwest Generation received a NOV from the US EPA alleging that Midwest Generation and Commonwealth Edison violated various provisions of the NSR rules as well as state air regulations. For information on the U.S. EPA NOV issued to Midwest Generation, See "EMG: Other Developments — Midwest Generation Potential Environmental Proceeding" above.

Ambient Air Quality Standards

Illinois

The Illinois EPA has begun to develop SIPs to meet National Ambient Air Quality Standards for 8-hour ozone and fine particulates with the intent of bringing non-attainment areas, such as Chicago, into attainment. The SIPs are expected to deal with all emission sources, not just power generators, and to address emissions of NO_X, SO_2, and volatile organic compounds. The SIP for 8-hour ozone was to be submitted to the US EPA by June 15, 2007, but is currently expected to be submitted in early 2008. The SIP for fine particulates is to be submitted to the US EPA by April 5, 2008.

The CPS requires Midwest Generation to install air pollution controls that will contribute to attainment with the ozone and fine particulate matter NAAQS. Midwest Generation expects, but cannot guarantee, that the reductions required under the agreement and the CPS will be sufficient for compliance with future ozone and particulate matter regulations. See "—Clean Air Interstate Rule — Illinois" for further discussion.

Water Quality Regulation

Clean Water Act — Cooling Water Intake Structures

California

The California State Water Resources Control Board is currently developing a draft state policy on ocean-based, once-through cooling in advance of the issuance of a final rule from the US EPA on Section 316(b) of the Clean Water Act. This policy may significantly impact both operations at San Onofre and SCE's ability to procure timely supplies of generating capacity from fossil-fueled plants that use ocean water in once-through cooling systems. Portions of the draft policy revealed by Board staff members in January 2008 suggest that the policy will show retrofitting existing plants with cooling towers as the best technology available for reducing detrimental effects on marine organisms as a result of once-through cooling. Additionally, target levels for compliance with the state policy will likely be at the high end of the ranges originally proposed in the US EPA's rule. Board members have commented publicly that a policy will be released by mid 2008 with workshops and public hearings to follow later in the year. Until the release of the draft policy, SCE is unable to predict its effect on SCE operations accurately, but it could result in significant additional capital expenditures and/or procurement costs.

State Water Quality Standards

Illinois

On October 26, 2007, the Illinois EPA filed a proposed rule with the Illinois Pollution Control Board (PCB) that would establish more stringent thermal and effluent water quality standards for the Chicago Area Waterway System and Lower Des Plaines River. Midwest Generation's Fisk, Crawford, Joliet and Will County stations all use water from the affected waterways for cooling purposes and the rule, if implemented, is expected to affect the manner in which those stations use water for station cooling. The proposed rule will be the subject of an administrative proceeding before the Illinois PCB and must be approved by the Illinois PCB and the Illinois Joint Committee on Administrative Rules. Following state adoption and approval, the US EPA also must approve the rule. Hearings began on January 28, 2008, and Midwest Generation is a party in those proceedings. At this time, it is not possible to predict the final form of the rule, how it would impact the operation of the affected stations, or the possible compliance costs or liability.

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 NPDES 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 the PADEP's approval, EME has undertaken a pilot program utilizing biological treatment. EME Homer City and the PADEP have entered into a consent order and agreement related to selenium discharge, which was entered by the Pennsylvania state court on July 17, 2007. Under the consent order and agreement, EME Homer City paid a civil penalty of $200,000 and agreed to install modifications to its wastewater system to achieve consistent compliance with discharge limits. EME Homer City has operated the wastewater treatment system for twelve months without a selenium exceedance. At this time EME expects to remain in compliance and consequently does not expect to install additional treatment systems.

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.

As of December 31, 2007, Edison International's recorded estimated minimum liability to remediate its 43 identified sites at SCE (24 sites) and EME (19 sites primarily related to Midwest Generation) was $70 million, $66 million of which was related to SCE, including $31 million related to San Onofre. This remediation liability is undiscounted. Edison International's other subsidiaries have no identified remediation sites. The ultimate costs to clean up Edison International's identified sites may vary from its recorded liability due to numerous uncertainties inherent in the estimation process, such as: the extent and nature of contamination; the scarcity of reliable data for identified sites; the varying costs of alternative cleanup methods; developments resulting from investigatory studies; the possibility of identifying additional sites; and the time periods over which site remediation is expected to occur. Edison International believes that, due to these uncertainties, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $147 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 its identified sites (sites in which the upper end of the range of costs is at least $1 million), SCE also has 30 immaterial sites whose total liability ranges from $3 million (the recorded minimum liability) to $9 million.

The CPUC allows SCE to recover environmental remediation costs at certain sites, representing $34 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 $64 million for its estimated minimum environmental-cleanup costs expected to be recovered through customer rates.

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

Edison International expects to clean up its identified sites over a period of up to 30 years. Remediation costs in each of the next several years are expected to range from $11 million to $31 million. Recorded costs $25 million, $14 million and $13 million for 2007, 2006 and 2005, respectively.

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

Federal and State Income Taxes

Tax Positions being addressed as part of active examinations and administrative appeals processes

Edison International remains subject to examination and administrative appeals by the IRS for tax years 1994 and forward. Edison International is challenging certain IRS deficiency adjustments for tax years 1994 – 1999 with the Administrative Appeals branch of the IRS and Edison International is currently under active IRS examination for tax years 2000 – 2002. In addition, the statute of limitations remains open for tax years 1986 – 1993, which has allowed Edison International to file certain affirmative claims related to these years.

In the examination phase for tax years 1994 – 1999, which is complete, the IRS asserted income tax deficiencies related to certain tax positions taken by Edison International on filed tax returns. Edison International is challenging the asserted tax deficiencies in IRS Appeals proceedings; however, most of the tax positions are timing differences and, therefore, any amounts that would be paid if Edison International's position is not sustained (exclusive of any penalties) would be deductible on future tax returns filed by Edison International. In addition, Edison International has filed affirmative claims with respect to certain tax years from 1986 through 2005 with the IRS and state tax authorities. Any benefits associated with these affirmative claims would be recorded in accordance with FIN 48 which provides that recognition would occur at the earlier of when Edison International makes an assessment that the affirmative claim position has a more likely than not probability of being sustained or when a settlement is consummated. Certain of these affirmative claims have been recognized as part of the implementation of FIN 48.

In April 2007, Edison International received a Notice of Proposed Adjustment from the California Franchise Tax Board for tax years 2001 and 2002 and is currently protesting the deficiencies asserted. Edison International remains subject to examination by the California Franchise Tax Board for tax years 2003 and forward. Edison International is also subject to examination by other state tax authorities, with varying statute of limitations.

Lease Transactions

As part of a nationwide challenge of U.S. taxpayers income tax treatment of certain types of lease transactions, the IRS has asserted deficiencies related to Edison International's deferral of income taxes associated with certain of its cross-border, leveraged leases. Edison International is challenging the asserted deficiencies in ongoing IRS Appeals proceedings for tax years 1994 – 1999.

The asserted deficiencies being addressed at IRS Appeals relate to Edison Capital's income tax treatment of both its 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) and its 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). As part of an ongoing examination of 2000 – 2002, the IRS is reviewing Edison International's income tax treatment of this Service Contract and has issued numerous data requests, which Edison International has provided responses. The IRS has not formally asserted any adjustments, but Edison International believes that the IRS examination team will assert deficiencies related to this Service Contract. The following table summarizes estimated federal and state income taxes deferred from these leases as of December 31, 2007. Repayment of these deferred taxes would be accelerated if the IRS position were to be sustained:

In millions	Tax Years Under Appeal 1994 – 1999	Tax Years Under Audit 2000 – 2002	Unaudited Tax Years 2003 – 2007	Total
Replacement Leases (SILO)	$ 44	$ 19	$ 27	$ 90
Lease/Leaseback (LILO)	563	566	(8)	1,121
Service Contract (SILO)	—	127	253	380
	$ 607	$ 712	$ 272	$ 1,591

As of December 31, 2007, the interest (after tax) on the proposed tax adjustments is estimated to be approximately $525 million. The IRS has also asserted 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 with the Administrative Appeals branch of the IRS appealing the deficiencies and penalties asserted by IRS examination for the tax years 1994 – 1999. Edison International believes the IRS's position misstates material facts, misapplies the law and is incorrect. Edison International is currently engaged in settlement discussions with IRS Appeals.

The payment of taxes, interest and penalties could have a significant impact on earnings and cash flow. Edison International is prepared to take legal action if an acceptable settlement cannot be reached with the IRS. If Edison International were to commence litigation in certain forums, Edison International would need to 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 recorded in "Other long-term assets" on the consolidated balance sheet and 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 which provides Edison International with the option of being able 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 and only case involving a LILO that has been decided was decided against the taxpayer on summary judgment in the Federal District Court in North Carolina. That taxpayer has appealed that decision to the Fourth Circuit Court of Appeals. Edison International cannot predict the timing or outcome of other pending LILO cases.

To the extent an acceptable settlement is not reached with the IRS, Edison International would expect 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. Edison International may make additional payments related to later tax years to preserve its litigation rights. Although, at this time, the amount and timing of these additional payments is uncertain, the amount of additional payments, if necessary, could be substantial. At this time, Edison International is unable to predict the impact of the ultimate resolution of the lease issues.

Edison International filed amended California Franchise Tax returns for tax years 1997 – 2002 to mitigate 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 described above and the SCE subsidiary contingent liability company transaction described below. Edison International filed these amended returns under protest retaining its appeal rights.

Balancing Account Over-Collections

In response to an affirmative claim related to balancing account over-collections, Edison International received an IRS Notice of Proposed Adjustment in July 2007. This affirmative claim is part of the ongoing IRS examinations and administrative appeals process and all of the tax years included in this Notice of Proposed Adjustment remain subject to ongoing examination and administrative appeals. The cash and earnings impacts of this position are dependent on the ultimate settlement of all open tax issues in these tax years. Edison International expects that resolution of this particular issue could potentially increase earnings and cash flow within the range of $70 million to $80 million and $300 million to $325 million, respectively.

Contingent Liability Company

The IRS has 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 for tax years 1997 – 1998. This is being considered by the Administrative Appeals branch of the IRS where Edison International is defending its tax return position with respect to this transaction.

California Apportionment

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 2006, Edison International recorded a $49 million benefit related to a tax reserve adjustment as a result of this settlement. In the FIN 48 adoption, a $54 million benefit was recorded related to this same issue. In addition, Edison International received a net cash refund of approximately $52 million in April 2007.

Resolution of Federal and State Income Tax Issues Being Addressed in Ongoing Examinations and Administrative Appeals

In 2008, Edison International will continue its efforts to resolve open tax issues through tax year 2002. Although the timing for resolving these open tax positions is uncertain, it is reasonably possible that all or a significant portion of these open tax issues through tax year 2002 could be resolved within the next 12 months.

Enterprise-Wide Software System Project

Progress continued during 2007 on preparation for the installation of the Enterprise Resource Planning system from SAP. On July 2, 2007, Edison International implemented procurement and material management systems at three of EMG's Illinois plants, as well as the EME financial systems. Implementation of these applications at the remaining Illinois plants and Homer City facilities began on September 1, 2007, and implementation of a fuel management system began on October 1, 2007. EME plans to implement the human resources systems in conjunction with the SCE human resource implementation. SCE expects to implement financial, supply chain, human resource and certain work management modules in 2008.

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 market 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 market, 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 market, 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 market 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 market on their behalves.

On December 20, 2007, Midway-Sunset entered into a settlement agreement with SCE, PG&E, SDG&E and certain California state parties to resolve Midway-Sunset's liability in the FERC refund proceedings. Midway-Sunset concurrently entered into a separate agreement with SCE and PG&E that provides for pro-rata reimbursement to Midway-Sunset by the two utilities of the portions of the agreed to refunds that are attributable to sales made by Midway-Sunset for the benefit of the utilities. The settlement has been approved by the CPUC but remains subject to approval by the FERC.

During the period in which Midway-Sunset's generation was sold into the PX market, amounts SCE received from Midway-Sunset for its pro-rata share of such sales 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.

MARKET RISK EXPOSURES

Big 4 Projects Power Purchase Agreements

Two of EME's Big 4 projects (the Sycamore project and the Watson project) have power purchase agreements with SCE that have transitioned, or are in the process of transitioning, to new pricing terms. Under FIN 46(R), Edison International and SCE consolidate these projects due to SCE's variable interest in these entities. The Sycamore project's long-term contract with SCE expired on December 31, 2007. SCE contends that its long-term power purchase agreement with the Watson project also expired on December 31, 2007. The Watson project contends that the agreement expires in April 2008. The two projects are currently selling electricity to SCE under terms and conditions contained in their prior long-term power purchase agreements with revised pricing terms as mandated by the CPUC. Edison International expects that pre-tax earnings from the Watson and Sycamore projects in aggregate will decrease by $80 million to $90 million during 2008. Any reduced costs to SCE resulting from these discussions will not impact SCE earnings because the savings flow through the regulatory recovery process to customers. EME expects that arrangements with both projects will eventually be replaced by new power purchase agreements, but cannot predict at this time whether or when this will occur or how the dispute concerning the proper termination date of the Watson power purchase agreement will be resolved.

Subprime U.S. Credit Market

Due to recent market developments, including a series of rating agency downgrades of subprime U.S. mortgage-related assets, the fair value of subprime-related investments have declined. Edison International has performed an assessment of its investments held in trusts related to its pension and postretirement benefits other than pensions, nuclear decommissioning obligations, and investments in cash. Edison International does not believe a decline in the fair value of the subprime-related investments will have a material impact on its trust assets or its investments in cash.

As of December 31, 2007, SCE had $977 million of tax-exempt and taxable pollution control bonds insured by AAA-rated bond insurers, namely Financial Guaranty Insurance Company (FGIC), MBIA Insurance Corporation (MBIA) and XL Capital Assurance Inc. (XL). Due to the exposure that these bond insurers have in connection with recent developments in the subprime credit market, the rating agencies have put these insurers on review for possible downgrade. Additionally, Fitch and Standard & Poor's have lowered FGIC's credit ratings from AAA to AA; and Moody's lowered FGIC's credit ratings from Aaa to A3. Fitch and

Moody's have lowered XL's credit ratings from AAA and Aaa to A and A3, respectively. Holders of the above mentioned insured SCE bonds have no ratings-related put rights and SCE expects these obligations to remain outstanding until contractual maturity with no change in financing terms and conditions.

However, the interest rates on one issue of SCE's taxable pollution control bonds insured by FGIC, totaling $249 million, are reset every 35 days through an auction process. Due to a loss of confidence in the creditworthiness of the bond insurers, there has been a significant reduction in market liquidity for auction rate bonds and interest rates on these bonds have risen. Consequently, SCE purchased in the secondary market $37 million of its auction rate bonds in December 2007 and $187 million in January and February 2008. The bonds remain outstanding and have not been retired or cancelled. The instruments under which the bonds were issued allow SCE to convert the bonds to other short-term variable-rate, term rate or fixed-rate modes. SCE may remarket the bonds in a term rate mode in the first half of 2008 and terminate the insurance covering the bonds.

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 Edison International's 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, 2007. Edison International's internal control over financial reporting as of December 31, 2007 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 2007 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 2007, 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.

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Report of Independent Registered Public Accounting Firm — Edison International

To the Board of Directors and Shareholders of Edison International

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, cash flows and changes in common shareholders' equity present fairly, in all material respects, the financial position of Edison International and its subsidiaries at December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Notes 1, 4, 5 and 8 to the consolidated financial statements, Edison International changed the manner in which it accounts for asset retirement costs as of December 31, 2005, stock-based compensation as of January 1, 2006, defined benefit pension and other post retirement plans as of December 31, 2006, and uncertain tax positions as of January 1, 2007.

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 27, 2008

Consolidated Statements of Income **Edison International**

In millions, except per-share amounts **Year ended December 31,**	**2007**	2006	2005
Electric utility	**$ 10,476**	$ 10,312	$ 9,500
Nonutility power generation	**2,575**	2,228	2,248
Financial services and other	**62**	82	104
Total operating revenue	**13,113**	12,622	11,852
Fuel	**1,875**	1,757	1,810
Purchased power	**3,124**	3,409	2,622
Provisions for regulatory adjustment clauses – net	**271**	25	435
Other operation and maintenance	**4,067**	3,762	3,609
Asset impairment and loss on lease termination	**—**	—	12
Depreciation, decommissioning and amortization	**1,264**	1,181	1,061
Net loss (gain) on sale of utility property and plant	**3**	(2)	(10)
Total operating expenses	**10,604**	10,132	9,539
Operating income	**2,509**	2,490	2,313
Interest and dividend income	**154**	169	112
Equity in income from partnerships and unconsolidated subsidiaries – net	**79**	79	136
Other nonoperating income	**95**	133	136
Interest expense – net of amounts capitalized	**(752)**	(807)	(794)
Impairment loss on equity method investment	**—**	—	(55)
Other nonoperating deductions	**(45)**	(63)	(67)
Loss on early extinguishment of debt	**(241)**	(146)	(25)
Income from continuing operations before tax and minority interest	**1,799**	1,855	1,756
Income tax expense	**492**	582	457
Dividends on preferred and preference stock of utility not subject to mandatory redemption	**51**	51	24
Minority interest	**156**	139	167
Income from continuing operations	**1,100**	1,083	1,108
Income (loss) from discontinued operations – net of tax	**(2)**	97	30
Income before accounting change	**1,098**	1,180	1,138
Cumulative effect of accounting change – net of tax	**—**	1	(1)
Net income	**$ 1,098**	$ 1,181	$ 1,137
Weighted-average shares of common stock outstanding	**326**	326	326
Basic earnings (loss) per share:			
Continuing operations	**$ 3.34**	$ 3.28	$ 3.38
Discontinued operations	**(0.01)**	0.30	0.09
Total	**$ 3.33**	$ 3.58	$ 3.47
Weighted-average shares, including effect of dilutive securities	**331**	330	332
Diluted earnings (loss) per share:			
Continuing operations	**$ 3.32**	$ 3.27	$ 3.36
Discontinued operations	**(0.01)**	0.30	0.09
Total	**$ 3.31**	$ 3.57	$ 3.45
Dividends declared per common share	**$ 1.175**	$ 1.10	$ 1.02

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,	2007	2006	2005
Net income	**$ 1,098**	$ 1,181	$ 1,137
Other comprehensive income (loss), net of tax:			
Foreign currency translation adjustments – net of income tax expense (benefit) of $(1), $(1) and $2 for 2007, 2006 and 2005 respectively	**(2)**	(1)	2
Pension and postretirement benefits other than pensions:			
Net loss arising during period – net of income tax benefit of $1 for 2007	**(2)**	—	—
Amortization of net loss included in expense – net of income tax expense of $3 for 2007	**5**	—	—
Amortization of prior service included in expense – net	**(1)**	—	—
Minimum pension liability adjustment – net of income tax expense of $3 in 2005	**—**	(1)	3
Unrealized gains (losses) on cash flow hedges:			
Other unrealized gains (losses) arising during the period – net of income tax expense (benefit) of $(160), $214 and $(52) for 2007, 2006 and 2005, respectively	**(234)**	314	(68)
Reclassification adjustment for gain (loss) included in net income – net of income tax expense (benefit) of $45, $9 and $(107) for 2007, 2006 and 2005, respectively	**64**	12	(159)
Other comprehensive income (loss)	**(170)**	324	(222)
Comprehensive income	**$ 928**	$ 1,505	$ 915

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

Consolidated Balance Sheets		Edison International
In millions December 31,	2007	2006
ASSETS		
Cash and equivalents	**$ 1,441**	$ 1,795
Restricted cash	**3**	59
Margin and collateral deposits	**141**	124
Receivables, less allowances of $34 and $29 for uncollectible accounts at respective dates	**1,033**	1,014
Accrued unbilled revenue	**370**	303
Fuel inventory	**116**	122
Materials and supplies	**316**	270
Accumulated deferred income taxes – net	**167**	203
Derivative assets	**110**	328
Regulatory assets	**197**	554
Short-term investments	**81**	558
Other current assets	**290**	152
Total current assets	**4,265**	5,482
Nonutility property – less accumulated provision for depreciation of $1,765 and $1,627 at respective dates	**4,906**	4,356
Nuclear decommissioning trusts	**3,378**	3,184
Investments in partnerships and unconsolidated subsidiaries	**272**	308
Investments in leveraged leases	**2,473**	2,495
Other investments	**96**	91
Total investments and other assets	**11,125**	10,434
Utility plant, at original cost:		
Transmission and distribution	**18,940**	17,606
Generation	**1,767**	1,465
Accumulated provision for depreciation	**(5,174)**	(4,821)
Construction work in progress	**1,693**	1,486
Nuclear fuel, at amortized cost	**177**	177
Total utility plant	**17,403**	15,913
Regulatory assets	**2,721**	2,818
Restricted cash	**48**	91
Margin and collateral deposits	**18**	4
Derivative assets	**122**	131
Rent payments in excess of levelized rent expense under plant operating leases	**716**	556
Other long-term assets	**1,144**	832
Total long-term assets	**4,769**	4,432
Total assets	**$ 37,562**	$ 36,261

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

Consolidated Balance Sheets		Edison International	
In millions, except share amounts	**December 31,**	**2007**	**2006**
LIABILITIES AND SHAREHOLDERS' EQUITY			
Short-term debt		**$ 500**	$ —
Long-term debt due within one year		**18**	488
Accounts payable		**979**	926
Accrued taxes		**49**	155
Accrued interest		**160**	196
Counterparty collateral		**42**	36
Customer deposits		**219**	198
Book overdrafts		**212**	140
Derivative liabilities		**149**	181
Regulatory liabilities		**1,019**	1,000
Other current liabilities		**933**	983
Total current liabilities		**4,280**	4,303
Long-term debt		**9,016**	9,101
Accumulated deferred income taxes – net		**5,196**	5,297
Accumulated deferred investment tax credits		**114**	122
Customer advances		**155**	160
Derivative liabilities		**116**	86
Power-purchase contracts		**22**	32
Accumulated provision for pensions and benefits		**1,089**	1,099
Asset retirement obligations		**2,892**	2,759
Regulatory liabilities		**3,433**	3,140
Other deferred credits and other long-term liabilities		**1,595**	1,267
Total deferred credits and other liabilities		**14,612**	13,962
Total liabilities		**27,908**	27,366
Commitments and contingencies (Note 6)			
Minority interest		**295**	271
Preferred and preference stock of utility not subject to mandatory redemption		**915**	915
Common stock, no par value (325,811,206 shares outstanding at each date)		**2,225**	2,080
Accumulated other comprehensive income (loss)		**(92)**	78
Retained earnings		**6,311**	5,551
Total common shareholders' equity		**8,444**	7,709
Total liabilities and shareholders' equity		**$ 37,562**	$ 36,261

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,**	**2007**	**2006**	**2005**
Cash flows from operating activities:			
Net income	**$ 1,098**	$ 1,181	$ 1,137
Less: income (loss) from discontinued operations	**(2)**	97	30
Income from continuing operations	**1,100**	1,084	1,107
Adjustments to reconcile to net cash provided by operating activities:			
Cumulative effect of accounting change – net of tax	**—**	(1)	1
Depreciation, decommissioning and amortization	**1,264**	1,181	1,061
Loss on impairment of nuclear decommissioning trusts	**58**	54	—
Other amortization	**111**	99	107
Stock-based compensation	**37**	47	48
Minority interest	**156**	139	167
Deferred income taxes and investment tax credits	**(39)**	(136)	160
Equity in income from partnerships and unconsolidated subsidiaries	**(75)**	(76)	(136)
Income from leveraged leases	**(49)**	(67)	(71)
Regulatory assets – long-term	**148**	92	387
Regulatory liabilities – long-term	**157**	18	(168)
Loss on early extinguishment of debt	**241**	146	25
Impairment losses	**—**	—	67
Levelized rent expense	**(160)**	(161)	(117)
Derivative assets – long-term	**(14)**	(8)	(42)
Derivative liabilities – long-term	**(67)**	50	97
Other assets	**(180)**	(231)	75
Other liabilities	**197**	307	1
Margin and collateral deposits – net of collateral received	**(24)**	601	(586)
Receivables and accrued unbilled revenue	**(59)**	208	(321)
Derivative assets – short-term	**111**	182	(233)
Derivative liabilities – short-term	**(108)**	(103)	137
Inventory and other current assets	**(121)**	(68)	(47)
Regulatory assets – short-term	**357**	(18)	17
Regulatory liabilities – short-term	**19**	318	192
Book overdrafts	**72**	—	—
Accrued interest and taxes	**12**	(123)	36
Accounts payable and other current liabilities	**18**	(121)	203
Distributions and dividends from unconsolidated entities	**33**	61	58
Operating cash flows from discontinued operations	**(2)**	94	22
Net cash provided by operating activities	**3,193**	3,568	2,247
Cash flows from financing activities:			
Long-term debt issued	**2,930**	2,350	1,325
Premiums paid on extinguishment of debt and issuance costs	**(241)**	(181)	(25)
Long-term debt repaid	**(3,215)**	(2,110)	(2,071)
Bonds repurchased	**(37)**	—	—
Issuance of preference stock	**—**	196	591
Redemption of preferred stock	**—**	—	(148)
Rate reduction notes repaid	**(246)**	(246)	(246)
Book overdrafts	**—**	(118)	25
Short-term debt financing – net	**500**	—	(88)
Shares purchased for stock-based compensation	**(215)**	(173)	(192)
Proceeds from stock option exercises	**86**	66	85
Excess tax benefits related to stock option exercises	**45**	27	—
Dividends to minority shareholders	**(106)**	(162)	(174)
Dividends paid	**(378)**	(352)	(326)
Net cash used by financing activities	**$ (877)**	$ (703)	$ (1,244)

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,**	**2007**	**2006**	**2005**
Cash flows from investing activities:			
Capital expenditures	**$ (2,826)**	$ (2,536)	$ (1,868)
Purchase of interest of acquired companies	**(33)**	(18)	(154)
Proceeds from sale of property and interest in projects	**2**	89	10
Proceeds from sale of discontinued operations	**—**	—	124
Proceeds from nuclear decommissioning trust sales	**3,697**	3,010	2,067
Purchases of nuclear decommissioning trusts investments and other	**(3,830)**	(3,150)	(2,159)
Proceeds from partnerships and unconsolidated subsidiaries, net of investment	**42**	25	132
Maturities and sales of short-term investments	**9,953**	7,128	2,928
Purchases of short-term investments	**(9,476)**	(7,474)	(2,999)
Restricted cash	**99**	13	53
Customer advances for construction and other investments	**(298)**	(50)	62
Investing cash flows from discontinued operations	**—**	—	5
Net cash used by investing activities	**(2,670)**	(2,963)	(1,799)
Effect of consolidation of variable interest entities on cash	**—**	—	3
Effect of exchange rate changes on cash	**—**	—	(1)
Net decrease in cash and equivalents	**(354)**	(98)	(794)
Cash and equivalents, beginning of year	**1,795**	1,893	2,689
Cash and equivalents, end of year	**1,441**	1,795	1,895
Cash and equivalents – discontinued operations	**—**	—	(2)
Cash and equivalents – continuing operations	**$ 1,441**	$ 1,795	$ 1,893

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

In millions	Common Stock	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Common Shareholders' Equity
Balance at December 31, 2004	$ 1,975	$ (4)	$ 4,078	$ 6,049
Net income			1,137	1,137
Other comprehensive loss		(222)		(222)
Common stock dividends 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 and other	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
Net income			1,181	1,181
Other comprehensive income		324		324
SFAS No. 158 – Pension and other postretirement benefits		(30)		(30)
Tax effect		10		10
Common stock dividends 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 and other	42			42
Excess tax benefits related to stock option exercises	28			28
Balance at December 31, 2006	$ 2,080	$ 78	$ 5,551	$ 7,709
Net income			1,098	1,098
FIN 48 adoption			250	250
Other comprehensive loss		(170)		(170)
Common stock dividends declared ($1.175) per share)			(383)	(383)
Shares purchased for stock-based compensation			(216)	(216)
Proceeds from stock option exercises			86	86
Noncash stock-based compensation and other	32		(7)	25
Excess tax benefits related to stock option exercises	45			45
Change in classification of shares purchased to settle performance shares	68		(68)	
Balance at December 31, 2007	**$ 2,225**	**$ (92)**	**$ 6,311**	**$ 8,444**

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.

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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; and EMG, a wholly owned non-utility subsidiary; EMG is the holding company of EME and Edison Capital. EME is an independent power producer engaged in the business of developing, acquiring, owning or leasing, operating and selling energy and capacity from independent power production facilities; EME also conducts hedging and energy trading activities in power markets open to competition. Edison Capital is a provider of capital and financial services. EME has domestic projects and one foreign project in Turkey; Edison Capital has domestic and foreign investments, primarily in Europe, Australia and Africa.

Basis of Presentation

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

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. 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 require creation of a regulatory liability for probable future costs collected through rates in advance of the actual costs being incurred. SCE' management continually evaluates the anticipated recovery of regulatory assets, liabilities, and revenue subject to refund and provides for allowances and/or reserves as appropriate.

Certain prior-year amounts were reclassified to conform to the December 31, 2007 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 timing difference associated with outstanding checks in excess of cash funds that are on deposit with financial institutions. SCE's ending daily cash funds are temporarily invested in short-term investments, until required for check clearings. 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 time deposits including certificates of deposit ($141 million and $439 million at December 31, 2007 and 2006, respectively) and other investments ($1.0 billion and $1.1 billion at December 31, 2007 and 2006, respectively) with original maturities of three months or less. Additionally, cash and equivalents of $110 million and $78 million at

December 31, 2007 and 2006, respectively 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 EMG) 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 $331 million at December 31, 2007 and $318 million at December 31, 2006 reflected in "Regulatory assets" in the long-term section of the consolidated balance sheets. Edison International had unamortized debt issuance costs of $83 million at December 31, 2007 and $96 million at December 31, 2006 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 as either assets or liabilities 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. All changes in the fair value of derivatives are recognized currently in earnings unless specific hedge criteria are met which requires Edison International to formally document, designate, and assess the effectiveness of hedge transactions. For those derivative transactions that qualify for and for which Edison International has elected hedge accounting, 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 fair value 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 remaining gain or loss on the derivative instrument, if any, is recognized currently in earnings.

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 VIEs or leases. 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 SCE's earnings. SCE has elected not to use hedge accounting for these transactions due to this regulatory accounting treatment.

Most of SCE's QF contracts are not required to be recorded on the consolidated balance sheets because they either do not 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. 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.

SCE enters into interest-locks to mitigate interest rate risk associated with future financings. SCE expects to recover any fair value changes associated with the interest-lock derivative instruments through regulatory mechanisms. Realized and unrealized gains and losses do not affect current earnings. Realized gains/losses are amortized and recovered through interest expense over the life of the new debt.

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 for trading positions and earnings at risk analysis for hedge positions. 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 operating revenues. 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 into 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 Notes 2 and 7.

Dividend Restriction

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, 2007, SCE's 13-month weighted-average common equity component of total capitalization was 50.59% resulting in the capacity to pay $308 million in additional dividends.

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 stock based compensation awards payable in common shares, including stock options, performance shares and restricted stock units, which earn dividend equivalents on an equal basis with common shares. Stock options awarded during the period 2003 through 2006 received dividend equivalents. Stock options awarded prior to 2002 and in 2007 were granted without a dividend equivalent feature. As a result of meeting a performance trigger, the options granted in 1998 and 1999 began earning dividend equivalents in 2006. Performance shares awarded in 2005 – 2007, received dividend equivalents. EPS was computed as follows:

In millions — Year Ended December 31,	2007	2006	2005
Basic earnings per share – continuing operations:			
Income from continuing operations	**$ 1,100**	$ 1,083	$ 1,108
Participating securities dividends	**(12)**	(14)	(7)
Income from continuing operations available to common shareholders	**$ 1,088**	$ 1,069	$ 1,101
Weighted average common shares outstanding	**326**	326	326
Basic earnings per share – continuing operations	**$ 3.34**	$ 3.28	$ 3.38
Diluted earnings per share – continuing operations:			
Income from continuing operations available to common shareholders	**$ 1,088**	$ 1,069	$ 1,101
Income impact of assumed conversions	**12**	11	15
Income from continuing operations available to common shareholders and assumed conversions	**$ 1,100**	$ 1,080	$ 1,116
Weighted average common shares outstanding	**326**	326	326
Incremental shares from assumed conversions	**5**	4	6
Adjusted weighted average shares – diluted	**331**	330	332
Diluted earnings per share – continuing operations	**$ 3.32**	$ 3.27	$ 3.36

Stock-based compensation awards of 83,901, 1,897,330 and 139,517 shares of common stock for the years ended December 31, 2007, 2006, and 2005, respectively, were not included in the computation of diluted earnings per share because the exercise price of the awards was greater than the average market price of the common shares, therefore, the effect would have been antidilutive.

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 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. 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. FIN 48 clarifies the accounting for uncertain tax positions. FIN 48 (adopted on January 1, 2007) requires an enterprise 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. Management continues to monitor and assess new income tax developments.

Investment tax credits are deferred and amortized over the lives of the related properties. Energy tax credits are also deferred and amortized over the term of the power purchase agreement of the respective project while production tax credits are recognized when earned. EME's investments in wind-powered electric generation projects qualify for federal production tax credits under Section 45 of the Internal Revenue Code. Such credits are allowable for production during the 10-year period after a qualifying wind energy facility is placed into service. Certain of EME's wind projects also qualify for state tax credits which are accounted for similarly as federal production tax credits.

Income tax expense includes the current tax liability from operations and the change in deferred income taxes during the year. Interest expense and penalties associated with income taxes are reflected in the caption "Income tax expense" on the consolidated statements of income.

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

Intangible Assets

Edison International accounts for acquired intangible assets in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets." All of these intangible assets relate to EME. Under SFAS No. 142, acquired intangible assets with indefinite lives are not amortized, rather they are tested for impairment. Intangible assets are periodically reviewed when impairment indicators are present to assess recoverability from future operations using undiscounted future cash flows in accordance with SFAS No. 144. For project development rights, the assets are subject to ongoing impairment analysis, such that if a project is no longer expected, the capitalized costs are written off.

Current intangible assets reflected in the caption "Other current assets" on Edison International's consolidated balance sheet, consist of emission allowances purchased by EME and amounted to $45 million at December 31, 2007.

Noncurrent intangible assets reflected in the caption "Other long-term assets" on Edison International's consolidated balance sheets mainly consist of EME's project development rights, options rights, and emission allowances and the total amounted to $61 million and $13 million, at December 31, 2007 and 2006, respectively. Amortized intangible assets are amortized using the straight-line method over five years.

In 2007 and 2006, project development rights relate to EME's consolidation of a development stage enterprise. In 2007, EME acquired six projects in Texas and Oklahoma which are in various stages of development with target completion dates of 2008 and beyond. The initial purchase price paid was recorded as project development rights. In 2007, EME recorded option rights pursuant to EME's joint development agreement entered into in December 2007 to develop jointly a portfolio of projects located in Arizona, Nevada and New Mexico. EME paid $24 million to acquire a 1% interest in twelve designated projects and the option to purchase the remaining 99%. The projects are in development with target completion dates of generally beyond 2008. EME is required to fund ongoing development expenses for each project.

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

Minimum lease payments under operating leases for property, plant and equipment are levelized (total minimum lease payments divided by the number of years of the lease) and recorded as rent expense over the terms of the leases. Lease payments in excess of the minimum are recorded as rent expense in the year incurred.

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.

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

In July 2006, the FASB issued FIN 48 which clarifies the accounting for uncertain tax positions. FIN 48 requires an enterprise 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 adopted FIN 48 effective January 1, 2007. Implementation of FIN 48 resulted in a cumulative-effect adjustment that increased retained earnings by $250 million upon adoption. 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 Note 4.

In July 2006, the FASB issued an FSP on accounting for a change in the timing of cash flows related to income taxes generated by a leverage lease transaction (FSP FAS 13-2). Edison International adopted FSP FAS 13-2 effective January 1, 2007. The adoption did not have any impact on Edison International's consolidated financial statements.

Accounting Pronouncements Not Yet Adopted

In April 2007, the FASB issued FIN 39-1. FIN 39-1 amends paragraph 3 of FIN No. 39 to replace the terms conditional contracts and exchange contracts with the term derivative instruments as defined in SFAS No. 133. FIN 39-1 also states that under master netting arrangements if collateral is based on fair value, then it must be netted with the fair value of derivative assets/liabilities if an entity qualified and elected the option to net those amounts. Edison International will adopt FIN 39-1 in the first quarter of 2008. The adoption is expected to result in netting a portion of margin and cash collateral deposits with derivative liabilities on Edison International's consolidated balance sheets, but will have no impact on Edison International's consolidated statements of income.

In February 2007, the FASB issued SFAS No. 159, which provides an option to report eligible financial assets and liabilities at fair value, with changes in fair value recognized in earnings. Edison International will adopt this pronouncement in the first quarter of 2008 and may elect to report certain financial assets and liabilities at fair value. The adoption is not expected to result in a cumulative-effect adjustment to retained earnings.

In September 2006, the FASB issued SFAS No. 157, which 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 in the first quarter of 2008. The adoption is not expected to result in any retrospective adjustments to its financial statements. The accounting requirements for employers' pension and other postretirement benefit plans is effective at the end of 2008 which is the next measurement date for these benefit plans. The effective date will be January 1, 2009 for asset retirement obligations and other nonfinancial liabilities which are not measured or disclosed on a recurring basis (at least annually).

In December 2007, the FASB issued SFAS No. 141(R), which establishes principles and requirements for how the acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at the acquisition date fair value. SFAS No. 141(R) determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. SFAS No. 141(R) applies prospectively to business combinations for which the acquisition date is on or after fiscal years beginning on or after January 1, 2009. Early adoption is not permitted.

In December 2007, the FASB issued SFAS No. 160, which requires an entity to clearly identify and present ownership interests in subsidiaries held by parties other than the entity in the consolidated financial statements within the equity section but separate from the entity's equity. It also requires the amount of consolidated net income attributable to the parent and to the noncontrolling interest to be clearly identified and presented on the face of the consolidated statement of income; changes in ownership interest be accounted for similarly as equity transactions; and, when a subsidiary is deconsolidated, any retained noncontrolling equity investment in the former subsidiary and the gain or loss on the deconsolidation of the subsidiary be measured at fair value. Edison International will adopt SFAS No. 160 on January 1, 2009 and is currently evaluating the impact of adopting SFAS No. 160 on its consolidated financial statements. In accordance with this standard, Edison International will reclassify minority interest to a component of shareholder's equity (at December 31, 2007 this amount was $295 million).

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 2024, 2025 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. See Note 8 for an analysis of the ARO liability.

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 trusts are accounted for in accordance with SFAS No. 115, and due to regulatory recovery of SCE nuclear decommissioning expense, rate-making accounting treatment is applied to all nuclear decommissioning trust activities in accordance with SFAS No. 71. As a result, nuclear decommissioning activities do not affect SCE's earnings.

SCE's nuclear decommissioning trust investments are classified as available-for-sale. SCE has debt and equity investments for the nuclear decommissioning trust funds. Contributions, earnings, and realized gains and losses (including other than temporary impairments) are recognized as revenue, and due to regulatory accounting treatment, also represent an increase in the nuclear obligation and increase decommissioning expense. Unrealized gains and losses on decommissioning trust funds increase or decrease the trust asset and the related regulatory asset or liability and have no impact on revenue or decommissioning expense. 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. 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. 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 2007, 4.2% for 2006 and 3.9% for 2005.

AFUDC – equity was $46 million in 2007, $32 million in 2006 and $25 million in 2005. AFUDC – debt was $24 million in 2007, $18 million in 2006 and $14 million in 2005.

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	38 years to 69 years	40 years
Distribution plant	30 years to 60 years	40 years
Transmission plant	35 years to 65 years	45 years
Other plant	5 years to 60 years	25 years

Nuclear fuel is recorded as utility plant (nuclear fuel in the fabrication and installation phase is recorded as construction in progress) in accordance with CPUC rate-making procedures. Nuclear fuel is amortized using the units of production method.

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 $24 million in 2007, $8 million in 2006 and $16 million in 2005. 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 shorter of the useful life or 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, 4.0% for 2007, 3.9% for 2006 and 4.0% for 2005.

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 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

Asset Retirement Obligations

Edison International accounts for its asset retirement obligations in accordance with SFAS No. 143 and FIN 47. AROs related to decommissioning of its nuclear power facilities are based on site-specific studies. The initial establishment of a nuclear-related ARO is at fair value and results in a corresponding regulatory asset (see "Nuclear Decommissioning" for further discussion). Over time, the liability is increased for accretion each period. Edison International's conditional AROs are recorded at fair value in the period in which it is incurred if the fair value can be reasonably estimated even though uncertainty exists about the timing and/or method of settlement. When the liability is initially recorded, the cost is capitalized by increasing the carrying amount of the related long-lived asset. Over time, the liability is increased to for accretion each period, and the capitalized cost is depreciated over the useful life of the related asset. Settlement of an ARO liability, for an amount other than its recorded amount, results in a gain or loss.

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, generally as determined by the average percentage of amounts written-off in prior 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, 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, relative amount of equity in investment, number of employees, or multi-factor method (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 $30 million in 2007, $26 million in 2006 and $24 million in 2005. EME's accounts receivable with this affiliate totaled $11 million and $7 million at December 31, 2007 and 2006, respectively.

Restricted Cash

Edison International had total restricted cash of $51 million at December 31, 2007 and $150 million at December 31, 2006. The restricted amounts included in current assets 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 lease payments and letter of credit expenses at EME. In addition, restricted cash included in current assets in 2006 also represented amounts used by SCE exclusively to make scheduled payments on the current maturities of rate reduction notes issued on behalf of SCE by a special purpose entity. These rate reduction notes were repaid in December 2007.

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 final approval. FERC rates are often implemented on an interim basis at the time when the rate change is filed. Revenue collected prior to a final FERC approval 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. Furthermore, amounts billed to ($2.3 billion in 2007, $2.5 billion in 2006 and $1.9 billion in 2005) 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 in nonutility power generation revenue. 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 are generally derived from leveraged leases, which are recorded by recognizing income over the term of the lease so as to produce a constant rate of return based on the investment leased.

Gains and losses from sale of assets are recognized at the time of the transaction.

Sales and Use Taxes

SCE bills certain sales and use taxes levied by state or local governments to its customers. Included in these sales and use taxes are franchise fees, which SCE pays to various municipalities (based on contracts with these municipalities) in order to operate within the limits of the municipality. SCE bills these franchise fees to its customers based on a CPUC-authorized rate. These franchise fees, which are required to be paid regardless of SCE's ability to collect from the customer, are accounted for on a gross basis and reflected in electric utility revenue and other operation and maintenance expense. SCE's franchise fees billed to customers and recorded as electric utility revenue were $104 million, $107 million and $82 million for the years ended December 31, 2007, 2006 and 2005, respectively. When SCE acts as an agent, and the tax is not required to be remitted if it is not collected from the customer, the taxes are accounted for on a net basis. Amounts billed to and collected from customers for these taxes are being remitted to the taxing authorities and are not recognized as revenue.

Short-term Investments

At different times during 2007, 2006 and 2005, Edison International held various variable rate demand notes related to short-term cash management activities. The interest rate process for these securities allow for a resetting of interest rates related to changes in terms and/or credit quality, similar to cash and cash equivalents. In accordance with SFAS No. 115, if on hand at the end of a period, these notes would be classified as short-term available-for-sale investment securities and recorded at fair value. There were no outstanding notes as of December 31, 2007 and 2006. Both sales and purchases of the notes were $9.5 billion, $7.5 billion and $3.0 billion for the years ended December 31, 2007, 2006 and 2005, respectively. There were no realized or unrealized gains or losses. The consolidated statements of cash flows were revised to reflect the 2006 and 2005 sales and purchases activity on a gross basis.

In addition, at December 31, 2007 and 2006, EME had classified all marketable debt securities as held-to-maturity and carried at amortized cost plus accrued interest which approximated their fair value. Gross unrealized holding gains and losses were not material.

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

In millions	**December 31,**	**2007**	**2006**
Commercial paper		**$ 32**	$ 417
Certificates of deposit		**41**	141
Treasury bills		**7**	—
Corporate bonds		**1**	—
Total		**$ 81**	$ 558

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

Stock-Based Compensation

Stock options, performance shares, deferred stock units and, beginning in 2007, restricted stock units have been granted under Edison International's long-term incentive compensation programs. 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 option exercises, performance shares, and restricted stock units. 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. Deferred stock units granted to management are settled in cash, not stock and represent a liability. Restricted stock units are settled in common stock; however, Edison International will substitute cash awards to the extent necessary to pay tax withholding or any government levies.

On April 26, 2007, Edison International's shareholders approved a new incentive plan (the 2007 Performance Incentive Plan) that includes stock-based compensation. No additional awards were granted under Edison International's prior stock-based compensation plans on or after April 26, 2007, and all future issuances will be made under the new plan. The maximum number of shares of Edison International's common stock that may be issued or transferred pursuant to awards under the new incentive plan is 8.5 million shares, plus the number of any shares subject to awards issued under Edison International's prior plans and outstanding as of April 26, 2007, which expire, cancel or terminate without being exercised or shares being issued. As of December 31, 2007, Edison International had approximately 8.4 million shares remaining for future issuance under its stock-based compensation plan. For further discussion see "Stock-Based Compensation" in Note 5.

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 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 $45 million and $27 million of excess tax benefits are classified as financing cash inflow in 2007 and 2006, respectively. 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.

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 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 $3 million and $8 million for 2007 and 2006, respectively, and would have increased $6 million for 2005.

Total stock-based compensation expense, net of amounts capitalized, (reflected in the caption “Other operation and maintenance” on the consolidated statements of income) was $42 million, $52 million and $81 million for 2007, 2006 and 2005, respectively. The income tax benefit recognized in the income statement was $17 million, $21 million and $32 million for 2007, 2006 and 2005, respectively. Total stock-based compensation cost capitalized was $4 million and $6 million for 2007 and 2006, respectively.

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

In millions **Year ended December 31,**	**2005**
Net income, as reported	$ 1,137
Add: stock-based compensation expense using the intrinsic value accounting method – net of tax	48
Less: stock-based compensation expense using the fair-value accounting method – net of tax	42
Pro forma net income	$ 1,143
Basic EPS:	
As reported	$ 3.47
Pro forma	$ 3.49
Diluted EPS:	
As reported	$ 3.45
Pro forma	$ 3.45

Note 2. Derivative Instruments and Hedging Activities

EME recorded net gains of approximately $149 million, $137 million and $202 million in 2007, 2006 and 2005, respectively, arising from energy trading activities, which are reflected in nonutility power generation revenue on the consolidated statements of income. EME netted 4.1 million MWh and 4.3 million MWh of sales and purchases of physically settled, gross purchases and sales during 2007 and 2006, respectively.

EME recorded net unrealized gains (losses) arising from nontrading derivative activities of $(35) million, $65 million and $(60) million in 2007, 2006 and 2005, respectively, which are reflected in nonutility power generation revenue on the consolidated statements of income.

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's realized and unrealized gains and losses arising from derivative instruments are reflected in purchased-power expense and offset through the provision for regulatory adjustment clauses – net on the consolidated statements of income and thus do not affect earnings, but may temporarily affect cash flows. The following is a summary of purchased-power expense:

In millions **For the year ended December 31,**	**2007**	**2006**	**2005**
Purchased power	**$ 3,117**	$ 3,013	$ 3,113
Unrealized (gains) losses on economic hedging activities – net	**(91)**	237	(90)
Realized (gains) losses on economic hedging activities – net	**132**	339	(115)
Energy settlements and refunds	**(34)**	(180)	(286)
Total purchased-power expense	**$ 3,124**	$ 3,409	$ 2,622

The changes in net realized and unrealized (gains) losses on economic hedging activities primarily resulted from changes in SCE's gas hedge portfolio mix as well as an increase in the natural gas futures market as of December 31, 2007 compared to December 31, 2006. Due to expected recovery through regulatory mechanisms unrealized gains and losses may temporarily affect cash flows, but do not affect earnings.

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, 2007, 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.

Redemption of MEHC Senior Secured Notes

On June 25, 2007, MEHC redeemed in full its senior secured notes. As a result of the redemption, EME is no longer subject to financial and investment restrictions that were contained in the indenture pursuant to which the senior secured notes were issued.

Senior Notes Offering

In 2006, EME issued $500 million of its 7.50% senior notes due 2013 and $500 million of its 7.75% senior notes due 2016. EME used the net proceeds of the offering, together with cash on hand, to purchase its 10% senior notes due 2008 and 9.875% senior notes due 2011. EME recorded a total pre-tax loss of $146 million ($90 million after tax) on early extinguishment of debt in 2006.

In 2007, EME issued $1.2 billion of its 7.00% senior notes due 2017, $800 million of its 7.20% senior notes due 2019 and $700 million of its 7.625% senior notes due 2027. EME pays interest on the senior notes on May 15 and November 15 of each year, beginning on November 15, 2007. The net proceeds were used, together with cash on hand, to purchase substantially all of EME's outstanding 7.73% senior notes due 2009 and all of Midwest Generation's 8.75% second priority senior secured notes due 2034; repay the outstanding balance of Midwest Generation's senior secured term loan facility; and make a dividend payment of $899 million to MEHC which enabled MEHC to purchase substantially all of its 13.5% senior secured notes due 2008. Edison International recorded a total pre-tax loss of approximately $241 million (approximately $148 million after tax) on early extinguishment of debt in 2007.

The senior notes are redeemable by EME at any time at a price equal to 100% of the principal amount plus accrued and unpaid interest and liquidated damages, if any, of the senior notes plus a "make-whole" premium. The senior notes are EME's senior unsecured obligations, ranking equal in right of payment to all of EME's existing and future senior unsecured indebtedness, and will be senior to all of EME's future subordinated indebtedness. EME's secured debt and its other secured obligations are effectively senior to the senior notes to the extent of the value of the assets securing such debt or other obligations. None of EME's subsidiaries have guaranteed the senior notes and, as a result, all the existing and future liabilities of EME's subsidiaries are effectively senior to the senior notes.

In connection with Midwest Generation's financing activities, EME has given a first security interest 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 $2.8 billion at December 31, 2007. 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 a 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 was a current property right created by the restructuring legislation and a financing order of the CPUC and consisted generally of the right to be paid a specified amount from nonbypassable rates charged to residential and small commercial customers. The rate reduction notes were repaid over 10 years with the final principal payment made in December 2007, through these nonbypassable residential and small commercial customer rates, which constitute the transition property purchased by SCE Funding LLC. The nonbypassable rates being charged to customers are expected to cease at the time of SCE's next consolidated rate change which is expected to be in March 2008. All amounts collected subsequent to the final principal payment made in December 2007 will be refunded to ratepayers. 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 were shown as long-term debt in the consolidated financial statements, SCE Funding LLC is legally separate from SCE. As a result of the payment of the bonds, SCE Funding LLC terminated its registration on December 27, 2007 and is no longer required to file reports with the U.S. Securities and Exchange Commission.

Long-term debt is:

In millions **December 31,**	**2007**	**2006**
First and refunding mortgage bonds:		
2009 – 2037 (4.65% to 6.0% and variable)	**$ 3,375**	$ 3,525
Rate reduction notes:		
2007 (6.42%)	**—**	246
Pollution-control bonds:		
2015 – 2035 (2.9% to 5.55% and variable)	**1,196**	1,196
Bonds repurchased	**(37)**	—
Debentures and notes:		
2009 – 2053 (noninterest-bearing to 8.75%)	**4,512**	4,641
Long-term debt due within one year	**(18)**	(488)
Unamortized debt discount – net	**(12)**	(19)
Total	**$ 9,016**	$ 9,101

Note: Rates and terms as of December 31, 2007.

In January 2008, SCE issued $600 million of 5.95% first and refunding mortgage bonds due in 2038. The proceeds were used to repay SCE's outstanding commercial paper of approximately $426 million and for general corporate purposes.

The interest rates on one issue of SCE's pollution control bonds insured by FGIC, totaling $249 million, are reset every 35 days through an auction process. Due to a loss of confidence in the creditworthiness of the bond insurers, there has been a significant reduction in market liquidity for auction rate bonds and interest rates on these bonds have risen. Consequently, SCE purchased in the secondary market $37 million of its auction rate bonds in December 2007 and $187 million in January and February 2008. The bonds remain outstanding and have not been retired or cancelled. The instruments under which the bonds were issued allow SCE to convert the bonds to other short-term variable-rate, term rate or fixed-rate modes. SCE may remarket the bonds in a term rate mode in the first half of 2008 and terminate the insurance covering the bonds.

Long-term debt maturities and sinking-fund requirements for the next five years are: 2008 – $18 million; 2009 – $175 million; 2010 – $314 million; 2011 – $14 million; and 2012 – $15 million.

Short-Term Debt

Short-term debt is generally used to finance fuel inventories, balancing account undercollections and general, temporary cash requirements including power purchase payments. At December 31, 2007, the outstanding short-term debt was $500 million at a weighted-average interest rate of 5.29%. There was no outstanding short-term debt at December 31, 2006.

Lines of Credit

At December 31, 2007, Edison International and its subsidiaries had $4.28 billion of borrowing capacity available under lines of credit totaling $5.1 billion. SCE had a $2.5 billion line of credit with $1.77 billion available. EME, including its subsidiary, Midwest Generation, had lines of credit of $1.0 billion available under lines of credit totaling $1.1 billion. Edison International (parent) had a $1.5 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.

During 2007, EME amended its existing $500 million secured credit facility maturing on June 15, 2012, increasing the total borrowings available thereunder to $600 million, and subject to the satisfaction of conditions as set forth in the secured credit facility, EME is permitted to increase the amount available under the secured credit facility to an amount that does not exceed 15% of EME's consolidated net tangible assets, as defined in the secured credit facility. Loans made under this credit facility bear interest, at EME's election, at either LIBOR (which is based on the interbank Eurodollar market) or the base rate (which is calculated as the higher of Citibank, N.A.'s publicly announced base rate and the federal funds rate in effect from time to time plus 0.50%) plus, in both cases, an applicable margin. The applicable margin depends on EME's debt ratings. At December 31, 2007, EME had no borrowings outstanding and $93 million of letters of credit outstanding under this credit facility. The credit facility contains financial covenants which require EME to maintain a minimum interest coverage ratio and a maximum corporate debt to corporate capital ratio. A failure to meet a ratio threshold could trigger other provisions, such as mandatory prepayment provisions or restrictions on dividends. At December 31, 2007, EME met both these ratio tests.

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 are deposited. EME is free to use these proceeds unless an event of default occurs under the credit facility.

During 2007, Midwest Generation also amended and restated its existing $500 million senior secured working capital facility. Loans made under this working capital facility bear interest at LIBOR + 0.55%. The working capital facility matures in 2012, with an option to extend for up to two years. The working capital facility contains financial covenants which require Midwest Generation to maintain a debt to capitalization ratio of no greater than 0.60 to 1. At December 31, 2007, the debt to capitalization ratio was 0.23 to 1. Midwest Generation uses its secured working capital facility to provide credit support for its hedging activities and for general working capital purposes. Midwest Generation can also support its hedging activities by granting liens to eligible hedge counterparties. As of December 31, 2007, Midwest Generation had no borrowings outstanding and $3 million of letters of credit had been utilized under the working capital 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 collateral 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. At December 31, 2007, the $2.5 billion credit facility supported $229 million in letters of credit and $500 million of short-term debt leaving $1.77 billion in available credit under its credit line. Also, 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.

Note 4. Income Taxes

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

In millions	Year ended December 31,	2007	2006	2005
Domestic		**$ 1,570**	$ 1,636	$ 1,557
Foreign		**22**	29	8
Total continuing operations		**1,592**	1,665	1,565
Discontinued operations		**3**	119	(11)
Accounting change		**—**	1	(2)
Total		**$ 1,595**	$ 1,785	$ 1,552

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

In millions	Year ended December 31,	2007	2006	2005
Current:				
Federal		**$ 359**	$ 652	$ 400
State		**95**	149	103
Foreign		**—**	1	(1)
		454	802	502
Deferred:				
Federal		**57**	(159)	16
State		**(19)**	(61)	(61)
		38	(220)	(45)
Total continuing operations		**492**	582	457
Discontinued operations		**5**	22	(40)
Accounting change		**—**	—	(1)
Total		**$ 497**	$ 604	$ 416

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

In millions December 31,	2007	2006
Deferred tax assets:		
Property-related	**$ 458**	$ 474
Unrealized gains and losses	**400**	373
Regulatory balancing accounts	**519**	496
Decommissioning	**182**	167
Accrued charges	**158**	149
Loss and credit carryforwards	**16**	22
Pension and PBOPs	**177**	215
Other	**545**	400
Total	**$ 2,455**	$ 2,296
Deferred tax liabilities:		
Property-related	**$ 3,636**	$ 3,560
Leveraged leases	**2,316**	2,268
Capitalized software costs	**128**	148
Regulatory balancing accounts	**521**	393
Unrealized gains and losses	**393**	367
Derivative-related	**—**	84
Other	**490**	570
Total	**$ 7,484**	$ 7,390
Accumulated net deferred income tax liability	**$ 5,029**	$ 5,094
Classification of accumulated deferred income taxes – net:		
Included in total deferred credits and other liabilities	**$ 5,196**	$ 5,297
Included in current assets	**$ 167**	$ 203

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

Year ended December 31,	2007	2006	2005
Federal statutory rate	**35.0%**	35.0%	35.0%
Tax reserve adjustments	**(3.5)**	2.5	(2.1)
Resolution of state audit issue	**—**	(3.0)	—
Resolution of 1991 – 1993 audit cycle	**—**	—	(3.9)
Housing and production credits	**(2.9)**	(2.1)	(2.0)
Property-related	**(0.2)**	0.2	0.2
Amortization of ITC credits	**(0.6)**	(0.5)	(0.5)
State tax – net of federal deduction	**4.1**	3.7	3.3
ESOP dividend payment	**(0.6)**	(0.6)	(0.7)
Other	**(0.4)**	(0.2)	(0.1)
Effective tax rate	**30.9%**	35.0%	29.2%

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 from continuing operations in 2007 was 30.9%. The decreased effective tax rate was caused primarily by reductions made to the income tax reserve to reflect progress in an administrative appeals process with the IRS related to SCE's income tax treatment of costs associated with environmental remediation, reductions made to the income tax reserves to reflect settlement of a state tax issue related to the April 2007 State Notice of Proposed Adjustment discussed below and due to production and low income housing credits at EMG.

The effective tax rate of 35.0% in 2006 reflected an SCE settlement with the California Franchise Tax Board regarding a state apportionment issue (see "California Apportionment") and production and low income housing tax credits at EMG, which served to reduce the effective tax rate, but this was partially offset by additional tax reserve accruals at SCE. The lower effective tax rate of 29.2% in 2005 was primarily due to the favorable resolution of the 1991 – 1993 IRS audit cycle, adjustments made to the tax reserve to reflect the impact of new IRS regulations and the favorable settlement of other federal and state tax audit issues at SCE and EMG.

Edison International and its subsidiaries had California net operating loss carryforwards with expirations dates beginning in 2012 of $54 million and $69 million at December 31, 2007 and 2006, respectively.

Accounting for Uncertainty in Income Taxes

Pursuant to the requirements of FIN 48, Edison International records tax reserves for uncertain tax return positions reflected on filed tax returns. Edison International also has filed affirmative tax claims for uncertain tax positions, reflecting potential refunds of taxes paid, or additional tax benefits for positions taken on prior tax returns. FIN 48 requires the disclosure of all unrecognized tax benefits, which includes the reserves recorded for uncertain tax positions on filed tax returns and the unrecognized portion of affirmative claims.

Unrecognized Tax Benefits Tabular Disclosure

The following table provides a reconciliation of unrecognized tax benefits from January 1, 2007 to December 31, 2007:

In millions	
Balance at January 1, 2007	$ 2,160
Tax positions taken during the current year	
Increases	69
Decreases	—
Tax positions taken during a prior year	
Increases	125
Decreases	(230)
Decreases for settlements during the period	(10)
Reductions for lapses of applicable statute of limitations	—
Balance at December 31, 2007	**$ 2,114**

The unrecognized tax benefits in the table above reflects affirmative claims related to timing differences of $1.6 billion and $1.7 billion, at December 31, 2007 and January 1, 2007, respectively, that have been claimed on amended tax returns, but have not met the recognition threshold pursuant to FIN 48 and have been denied by the IRS as part of their examinations. These affirmative claims remain unpaid by the IRS and no receivable has been recorded. Edison International is vigorously defending these affirmative claims in IRS administrative appeals proceedings.

It is reasonably possible that Edison International could reach a settlement with the IRS to all or a portion of the unrecognized tax benefits through tax year 2002 within the next 12 months. Edison International believes that that it is reasonably possible that unrecognized tax benefits could be reduced by an amount up to $1.3 billion within the next 12 months.

The total amount of unrecognized tax benefits as of December 31, 2007 and January 1, 2007 that, if recognized, would have an effective tax rate impact is $206 million and $189 million, respectively.

The total amount of accrued interest and penalties were $162 million and $119 million as of December 31, 2007 and January 1, 2007, respectively. In 2007, $12 million of after-tax interest income was recognized and included in income tax expense.

Tax Positions being addressed as part of active examinations and administrative appeals processes

Edison International remains subject to examination and administrative appeals by the IRS for tax years 1994 and forward. Edison International is challenging certain IRS deficiency adjustments for tax years 1994 – 1999 with the Administrative Appeals branch of the IRS and Edison International is currently under active IRS examination for tax years 2000 – 2002. In addition, the statute of limitations remains open for tax years 1986 – 1993, which has allowed Edison International to file certain affirmative claims related to these years.

In the examination phase for tax years 1994 – 1999, which is complete, the IRS asserted income tax deficiencies related to certain tax positions taken by Edison International on filed tax returns. Edison International is challenging the asserted tax deficiencies in IRS Appeals proceedings; however, most of the tax positions are timing differences and, therefore, any amounts that would be paid if Edison International's position is not sustained (exclusive of any penalties) would be deductible on future tax returns filed by Edison International. In addition, Edison International has filed affirmative claims with respect to certain tax years from 1986 through 2005 with the IRS and state tax authorities. Any benefits associated with these affirmative claims would be recorded in accordance with FIN 48 which provides that recognition would occur at the earlier of when Edison International makes an assessment that the affirmative claim position has a more likely than not probability of being sustained or when a settlement is consummated. Certain of these affirmative claims have been recognized as part of the implementation of FIN 48.

In April 2007, Edison International received a Notice of Proposed Adjustment from the California Franchise Tax Board for tax years 2001 and 2002 and is currently protesting the deficiencies asserted. Edison International remains subject to examination by the California Franchise Tax Board for tax years 2003 and forward. Edison International is also subject to examination by other state tax authorities, with varying statute of limitations.

Lease Transactions

As part of a nationwide challenge of U.S. taxpayers' income tax treatment of certain types of lease transactions, the IRS has asserted deficiencies related to Edison International's deferral of income taxes associated with certain of its cross-border, leveraged leases. Edison International is challenging the asserted deficiencies in ongoing IRS Appeals proceedings for tax years 1994 – 1999.

The asserted deficiencies being addressed at IRS Appeals relate to Edison Capital's income tax treatment of both its 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) and its 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). As part of an ongoing examination of 2000 – 2002, the IRS is reviewing Edison International's income tax treatment of this Service Contract and has issued numerous data requests, which Edison International has provided responses. The IRS has not formally asserted any adjustments, but Edison International believes that the IRS examination team will assert deficiencies related to this Service Contract. The following table summarizes estimated federal and state income taxes deferred from these leases as of December 31, 2007. Repayment of these deferred taxes would be accelerated if the IRS position were to be sustained:

In millions	Tax Years Under Appeal 1994 – 1999	Tax Years Under Audit 2000 – 2002	Unaudited Tax Years 2003 – 2007	Total
Replacement Leases (SILO)	$ 44	$ 19	$ 27	$ 90
Lease/Leaseback (LILO)	563	566	(8)	1,121
Service Contract (SILO)	—	127	253	380
	$ 607	$ 712	$ 272	$ 1,591

As of December 31, 2007, the interest (after tax) on the proposed tax adjustments is estimated to be approximately $525 million. The IRS has also asserted 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 with the Administrative Appeals branch of the IRS appealing the deficiencies and penalties asserted by IRS examination for the tax years 1994 – 1999. Edison International believes the IRS's position misstates material facts, misapplies the law and is incorrect. Edison International is currently engaged in settlement discussions with IRS Appeals.

The payment of taxes, interest and penalties could have a significant impact on earnings and cash flow. Edison International is prepared to take legal action if an acceptable settlement cannot be reached with the IRS. If Edison International were to commence litigation in certain forums, Edison International would need to 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 recorded in "Other long-term assets" on the consolidated balance sheet and 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 which provides Edison International with the option of being able 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 and only case involving a LILO that has been decided was decided against the taxpayer on summary judgment in the Federal District Court in North Carolina. That taxpayer has appealed that decision to the Fourth Circuit Court of Appeals. Edison International cannot predict the timing or outcome of other pending LILO cases.

To the extent an acceptable settlement is not reached with the IRS, Edison International would expect 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. Edison International may make additional payments related to later tax years to preserve its litigation rights. Although, at this time, the amount and timing of these additional payments is uncertain, the amount of additional payments, if necessary, could be substantial. At this time, Edison International is unable to predict the impact of the ultimate resolution of the lease issues.

Edison International filed amended California Franchise Tax returns for tax years 1997 – 2002 to mitigate 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 described above and the SCE subsidiary contingent liability company transaction described below. Edison International filed these amended returns under protest retaining its appeal rights.

Balancing Account Over-Collections

In response to an affirmative claim related to balancing account over-collections, Edison International received an IRS Notice of Proposed Adjustment in July 2007. This affirmative claim is part of the ongoing IRS examinations and administrative appeals process and all of the tax years included in this Notice of Proposed Adjustment remain subject to ongoing examination and administrative appeals. The cash and earnings impacts of this position are dependent on the ultimate settlement of all open tax issues in these tax years. Edison International expects that resolution of this particular issue could potentially increase earnings and cash flow within the range of $70 million to $80 million and $300 million to $325 million, respectively.

Contingent Liability Company

The IRS has 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 for tax years 1997 – 1998. This is being considered by the Administrative Appeals branch of the IRS where Edison International is defending its tax return position with respect to this transaction.

California Apportionment

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 2006, Edison International recorded a $49 million benefit related to a tax reserve adjustment as a result of this settlement. In the FIN 48 adoption, a $54 million benefit was recorded related to this same issue. In addition, Edison International received a net cash refund of approximately $52 million in April 2007.

Resolution of Federal and State Income Tax Issues Being Addressed in Ongoing Examinations and Administrative Appeals

In 2008, Edison International will continue its efforts to resolve open tax issues through tax year 2002. Although the timing for resolving these open tax positions is uncertain, it is reasonably possible that all or a significant portion of these open tax issues through tax year 2002 could be resolved within the next 12 months.

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 $73 million in 2007, $69 million in 2006 and $64 million in 2005.

Pension Plans and Postretirement Benefits Other Than Pensions

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 normally offset through other comprehensive income (loss). Edison International adopted SFAS No. 158 as of December 31, 2006. In accordance with SFAS No. 71, 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. 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.

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.

The expected contributions (all by the employer) are approximately $68 million for the year ending December 31, 2008. This amount is subject to change based on the funded status at year-end and the tax deductible limitations.

The fair value of plan assets is determined primarily by quoted market prices.

Information on plan assets and benefit obligations is shown below:

In millions Year ended December 31,	2007	2006
Change in projected benefit obligation		
Projected benefit obligation at beginning of year	**$ 3,410**	$ 3,418
Service cost	**117**	118
Interest cost	**185**	181
Amendments	**(5)**	12
Actuarial loss (gain)	**(97)**	(48)
Special termination benefits	**2**	8
Benefits paid	**(257)**	(279)
Projected benefit obligation at end of year	**$ 3,355**	$ 3,410
Change in plan assets		
Fair value of plan assets at beginning of year	**$ 3,458**	$ 3,199
Actual return on plan assets	**294**	488
Employer contributions	**102**	50
Benefits paid	**(257)**	(279)
Fair value of plan assets at end of year	**$ 3,597**	$ 3,458
Funded status at end of year	**$ 242**	$ 48
Amounts recognized in the consolidated balance sheets consist of:		
Long-term assets	**$ 430**	$ 226
Current liabilities	**(8)**	(8)
Long-term liabilities	**(180)**	(170)
	$ 242	$ 48
Amounts recognized in accumulated other comprehensive loss consist of:		
Prior service cost	**$ 3**	$ 4
Net loss	**37**	42
	$ 40	$ 46
Additional detail of amount recognized as a regulatory liability:		
Prior service cost	**$ 49**	$ 71
Net (gain)	**$ (357)**	$ (215)
Accumulated benefit obligation at end of year	**$ 2,992**	$ 2,987
Pension plans with an accumulated benefit obligation in excess of plan assets:		
Projected benefit obligation	**$ 276**	$ 232
Accumulated benefit obligation	**$ 232**	$ 197
Fair value of plan assets	**$ 88**	$ 60
Weighted-average assumptions used to determine obligations at end of year:		
Discount rate	**6.25%**	5.75%
Rate of compensation increase	**5.0%**	5.0%

Expense components and other amounts recognized in other comprehensive income:

Expense components are:

In millions Year ended December 31,	2007	2006	2005
Service cost	**$ 117**	$ 118	$ 117
Interest cost	**185**	181	175
Expected return on plan assets	**(245)**	(232)	(221)
Special termination benefits	**2**	8	—
Amortization of transition obligation	**—**	—	1
Amortization of prior service cost	**17**	16	16
Amortization of net loss	**6**	6	6
Expense under accounting standards	**$ 82**	$ 97	$ 94
Regulatory adjustment – deferred	**(3)**	(10)	(26)
Total expense recognized	**$ 79**	$ 87	$ 68

Other changes in plan assets and benefit obligations recognized in other comprehensive income:

In millions Year ended December 31,	2007
Net loss (gain)	**$ —**
Prior service cost	**—**
Amortization of prior service cost	**(1)**
Amortization of net gain	**(6)**
Total recognized in other comprehensive income	**$ (7)**
Total recognized in expense and other comprehensive income	**$ 72**

Effective with the adoption of SFAS No. 158, as of December 31, 2006, and in accordance with SFAS No. 71, Edison International records 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. The estimated amortization amounts for 2008 are $17 million for prior service cost and $1 million for net loss including $1 million and $6 million respectively, reclassified from other comprehensive income.

Due to the Mohave shutdown, SCE has incurred costs for special termination benefits.

The following are weighted-average assumptions used to determine expense:

Year ended December 31,	2007	2006	2005
Discount rate	**5.75%**	5.5%	5.5%
Rate of compensation increase	**5.0%**	5.0%	5.0%
Expected long-term return on plan assets	**7.5%**	7.5%	7.5%

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

In millions Year ended December 31,	
2008	$ 274
2009	$ 283
2010	$ 291
2011	$ 307
2012	$ 314
2013 – 2017	$ 1,591

The following are asset allocations by investment category:

	Target for 2008	December 31, 2007	December 31, 2006
United States equities	45%	**47%**	47%
Non-United States equities	25%	**25%**	26%
Private equities	4%	**2%**	2%
Fixed income	26%	**26%**	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.

The expected contributions (all by the employer) to the PBOP trust are $42 million for the year ending December 31, 2008. This amount is subject to change based on the funded status at year-end and the tax deductible limitations.

The fair value of plan assets is determined primarily by quoted market prices.

Information on plan assets and benefit obligations is shown below:

In millions Year ended December 31,	2007	2006
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 2,260**	$ 2,357
Service cost	**45**	45
Interest cost	**130**	120
Amendments	**7**	—
Actuarial gain	**(77)**	(163)
Special termination benefits	**1**	4
Plan participants' contributions	**9**	7
Medicare Part D subsidy received	**4**	3
Benefits paid	**(108)**	(113)
Benefit obligation at end of year	**$ 2,271**	$ 2,260
Change in plan assets		
Fair value of plan assets at beginning of year	**$ 1,743**	$ 1,573
Actual return on assets	**117**	203
Employer contributions	**51**	70
Plan participants' contributions	**9**	7
Medicare Part D subsidy received	**4**	3
Benefits paid	**(108)**	(113)
Fair value of plan assets at end of year	**$ 1,816**	$ 1,743
Funded status at end of year	**$ (455)**	$ (517)
Amounts recognized in the consolidated balance sheets consist of:		
Current liabilities	**$ (20)**	$ (21)
Long-term liabilities	**(435)**	(496)
	$ (455)	$ (517)
Amounts recognized in accumulated other comprehensive loss (income) consist of:		
Prior service cost (credit)	**$ (9)**	(11)
Net loss	**20**	19
	$ 11	$ 8
Additional detail of amounts recognized as a regulatory asset:		
Prior service cost (credit)	**$ (206)**	$ (242)
Net loss	**$ 437**	$ 545
Weighted-average assumptions used to determine obligations at end of year:		
Discount rate	**6.25%**	5.75%
Assumed health care cost trend rates:		
Rate assumed for following year	**9.25%**	9.25%
Ultimate rate	**5.0%**	5.0%
Year ultimate rate reached	**2015**	2011

Expense components and other amounts recognized in other comprehensive income:

Expense components are:

In millions Year ended December 31,	2007	2006	2005
Service cost	**$ 45**	$ 45	$ 46
Interest cost	**130**	120	123
Expected return on plan assets	**(118)**	(105)	(101)
Special termination benefits	**1**	4	—
Amortization of prior service cost (credit)	**(31)**	(31)	(30)
Amortization of net loss	**30**	43	47
Total expense	**$ 57**	$ 76	$ 85

Other changes in plan assets and benefit obligations recognized in other comprehensive income:

In millions Year ended December 31,	2007
Net loss gain	**$ 3**
Prior service cost	**—**
Amortization of prior service cost (credit)	**2**
Amortization of net gain	**(2)**
Total recognized in other comprehensive income	**$ 3**
Total recognized in expense and other comprehensive income	**$ 60**

Effective with the adoption of SFAS No. 158, as of December 31, 2006, and in accordance with SFAS No. 71, Edison International records 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. The estimated amortization amounts for 2008 are $(31) million for prior service cost (credit) and $17 million for net loss including $(2) million and $1 million respectively, reclassified from other comprehensive income.

Due to the Mohave shutdown, SCE has incurred costs for special termination benefits.

The following are weighted-average assumptions used to determine expense:

Year ended December 31,	2007	2006	2005
Discount rate	**5.75%**	5.5%	5.75%
Expected long-term return on plan assets	**7.0%**	7.0%	7.1%
Assumed health care cost trend rates:			
Current year	**9.25%**	10.25%	10.0%
Ultimate rate	**5.0%**	5.0%	5.0%
Year ultimate rate reached	**2015**	2011	2010

Increasing the health care cost trend rate by one percentage point would increase the accumulated benefit obligation as of December 31, 2007 by $273 million and annual aggregate service and interest costs by $20 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated benefit obligation as of December 31, 2007 by $243 million and annual aggregate service and interest costs by $18 million.

The following are benefit payments expected to be paid:

In millions	Year ending December 31,	Before Subsidy*	Net
2008		$ 104	$ 99
2009		$ 113	$ 107
2010		$ 121	$ 114
2011		$ 132	$ 124
2012		$ 141	$ 133
2013 – 2017		$ 834	$ 777

* Medicare Part D prescription drug benefits

The following are asset allocations by investment category:

	Target for 2008	December 31, 2007	2006
United States equities	64%	**62%**	64%
Non-United States equities	16%	**14%**	13%
Fixed income	20%	**24%**	23%

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 stocks 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 positions 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 has granted stock options at exercise prices equal to the average of the high and low price, and beginning in 2007, at the closing price at the grant date. Edison International may grant stock options 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 expense, net of amounts capitalized, associated with stock options was $25 million and $37 million for 2007 and 2006, respectively. Under prior accounting rules, there was no comparable expense recognized for the same period in 2005. See "Stock-Based Compensation" in Note 1 for further discussion.

Stock options granted in 2003 through 2006 accrue dividend equivalents for the first five years of the option term. Stock options granted in 2007 have no dividend equivalent rights. 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,	2007	2006	2005
Expected terms (in years)	**7.5**	9 to 10	9 to 10
Risk-free interest rate	**4.6% – 4.8%**	4.3% – 4.7%	4.1% – 4.3%
Expected dividend yield	**2.1% – 2.4%**	2.3% – 2.8%	2.1% – 3.1%
Weighted-average expected dividend yield	**2.4%**	2.4%	3.1%
Expected volatility	**16% – 17%**	16% – 17%	15% – 20%
Weighted-average volatility	**16.5%**	16.3%	19.5%

The expected term represents the period of time for which the options are expected to be outstanding and is based on historical exercise and post-vesting cancellation experience and stock price history. 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 2007 and 2006, expected volatility is based on the historical volatility of Edison International's common stock for the most 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.

The following is a summary of the status of Edison International stock options:

		Weighted-Average		
	Stock Options	**Exercise Price**	**Remaining Contractual Term (Years)**	**Aggregate Intrinsic Value**
Outstanding at December 31, 2006	14,111,697	$ 26.33		
Granted	1,815,861	$ 47.76		
Expired	—	—		
Forfeited	(55,632)	$ 42.04		
Exercised	(3,766,284)	$ 22.84		
Outstanding at December 31, 2007	**12,105,642**	**$ 30.55**	**6.41**	
Vested and expected to vest at December 31, 2007	11,613,396	$ 30.19	6.35	$ 258,540,909
Exercisable at December 31, 2007	**6,324,576**	**$ 23.60**	**5.25**	**$ 182,478,564**

Stock options granted in 2007 do not accrue dividend equivalents except for options granted to Edison International's Board of Directors.

The weighted-average grant-date fair value of options granted during 2007, 2006 and 2005 was $11.44, $14.42 and $11.82, respectively. The total intrinsic value of options exercised during 2007, 2006 and 2005 was $109 million, $70 million and $77 million, respectively. At December 31, 2007, there was $23 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 2007, 2006 and 2005 was $27 million, $45 million and $26 million, respectively.

The amount of cash used to settle stock options exercised was $195 million, $136 million and $162 million for 2007, 2006, and 2005, respectively. Cash received from options exercised for 2007, 2006 and 2005 was $86 million, $66 million and $85 million, respectively. The estimated tax benefit from options exercised for 2007, 2006 and 2005 was $43 million, $27 million and $30 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 was $20 million.

Performance Shares

A target number of contingent performance shares were awarded to executives in January 2005, March 2006 and March 2007, and vest at the end of December 2007, 2008 and 2009, respectively. Performance shares awarded in 2005 and 2006 accrue dividend equivalents which accumulate without interest and will be payable in cash following the end of the performance period when the performance shares are paid. Edison International has discretion to pay certain dividend equivalents in Edison International common stock.

Performance shares awarded in 2007 contain dividend equivalent reinvestment rights. An additional number of target contingent performance shares will be credited based on dividends on Edison International common stock for which the ex-dividend date falls within the performance period. 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, net of amounts capitalized, associated with performance shares was $12 million, $15 million and $59 million for 2007, 2006 and 2005, respectively. The amount of cash used to settle performance shares classified as equity awards was $20 million, $37 million and $3 million for 2007, 2006 and 2005, respectively. In 2007 we changed the classification of the cash paid for the settlements of performance shares from common stock to retained earnings to conform with the classification for settlements of stock option exercises.

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 2007, 2006 and 2005 performance shares classified as share-based equity awards was 4.8%, 4.1% and 2.7%, respectively. Edison International's expected volatility used to determine the grant date fair values for the 2007, 2006 and 2005 performance shares classified as share-based equity awards was 16.5%, 16.2% and 27.7%, 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, 2007 was 4.3% and 17.1%, respectively. 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 2007, 2006 and 2005 was $44 million, $73 million and $40 million, respectively, which included cash paid to settle the performance shares classified as liability awards for 2007, 2006 and 2005 of $14 million, $24 million and $13 million, respectively. At December 31, 2007, there was $5 million (based on the December 31, 2007 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 two years. The fair value of performance shares vested during 2007, 2006 and 2005 was $17 million, $27 million and $42 million, respectively.

The following is a summary of the status of Edison International nonvested performance shares classified as equity awards:

	Performance Shares	Weighted-Average Grant-Date Fair Value
Nonvested at December 31, 2006	202,614	$ 48.83
Granted	69,012	$ 57.55
Forfeited	(1,092)	$ 56.77
Paid out	(121,035)	$ 46.09
Nonvested at December 31, 2007	**149,499**	**$ 55.01**

The weighted-average grant-date fair value of performance shares classified as equity awards granted during 2006 and 2005 was $52.90 and $46.09, respectively.

The following is 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):

	Performance Shares	Weighted-Average Fair Value
Nonvested at December 31, 2006	202,769	
Granted	69,113	
Forfeited	(1,096)	
Paid out	(121,106)	
Nonvested at December 31, 2007	**149,680**	**$ 44.52**

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 2006, SCE modified 62 power contracts. No contracts were modified in 2007. 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 provisions 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 lease on a straight-line basis. At December 31, 2007, the net liability was $59 million. At December 31, 2007, SCE had 67 power contracts classified as operating leases. Operating lease expense for power purchases was $297 million in 2007, $188 million in 2006, and $68 million in 2005. In addition, SCE executed a power purchase contract in late 2005 and an additional power purchase contract in June 2007 which met the requirements for capital leases. These capital leases have a net commitment of $20 million at December 31, 2007 and $13 million at

December 31, 2006. SCE's capital lease executory costs and interest expense was $2 million in 2007 and $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. The gain on the sale of the power facilities has been deferred and is being amortized over the term of the leases.

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 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. The gain on the sale of the power facilities has been deferred and is being amortized over the term of the leases.

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

In millions	Year ending December 31,	Power Contracts Operating Leases	Other Operating Leases
2008		$ 566	$ 414
2009		647	409
2010		610	391
2011		400	365
2012		240	358
Thereafter		1,414	2,483
Total		**$ 3,877**	**$ 4,420**

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 $539 million in 2007, $420 million in 2006 and $289 million in 2005.

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 $2.8 billion as of December 31, 2007, based on site-specific studies performed in 2005 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 effective January 2007, receive contributions of 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 ($89 million at December 31, 2007). Total expenditures for the decommissioning of San Onofre Unit 1 were $538 million from the beginning of the project in 1998 through December 31, 2007.

Decommissioning expense under the rate-making method was $131 million, $161 million and $118 million in 2007, 2006 and 2005, respectively. The ARO for decommissioning SCE's active nuclear facilities was $2.7 billion and $2.6 billion at December 31, 2007 and 2006, respectively.

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, 2007	December 31, 2006
Municipal bonds	2008 – 2044	**$ 561**	$ 692
Stocks	–	**1,968**	1,611
United States government issues	2008 – 2049	**552**	729
Corporate bonds	2008 – 2047	**241**	104
Short-term	2008	**56**	48
Total		**$ 3,378**	$ 3,184

Note: Maturity dates as of December 31, 2007.

Trust fund earnings (based on specific identification) increase the trust fund balance and the ARO regulatory liability. Net earnings were $143 million, $130 million and $87 million in 2007, 2006 and 2005, respectively. Proceeds from sales of securities (which are reinvested) were $3.3 billion, $3.0 billion and $2.0 billion in 2007, 2006 2005, respectively. Unrealized holding gains, net of losses, were $1.1 billion, $1.0 billion and $852 million at December 31, 2007, 2006 and 2005, respectively. Realized losses for other-than-temporary impairments were $58 million and $54 million for the year ended December 31, 2007 and 2006, respectively. Approximately 92% 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.

At December 31, 2007, 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 10 years.

At December 31, 2007, EME's subsidiaries had contractual commitments for the transport of coal to their respective facilities. Midwest Generation's primary contract is with Union Pacific Railroad (and various delivering 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.

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 2008 through 2012 are estimated below:

In millions	**2008**	**2009**	**2010**	**2011**	**2012**
Fuel supply	$ 541	$ 407	$ 223	$ 77	$ 73
Gas and coal transportation payments	$ 253	$ 168	$ 172	$ 8	$ 8
Purchased power	$ 410	$ 324	$ 294	$ 290	$ 339

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 $53 million through 2016 (approximately $6 million per year).

At December 31, 2007, EME's subsidiaries had firm commitments to spend approximately $249 million in 2008 and $4 million in 2009 on capital and construction expenditures. The majority of these expenditures relate to the construction of wind projects. These expenditures are planned to be financed by cash on hand, cash generated from operations or existing subsidiary credit agreements.

At December 31, 2007, EME had entered into agreements with vendors securing 483 wind turbines (1,076 MW) with remaining commitments of $481 million in 2008, $540 million in 2009 and $49 million in 2010. At December 31, 2007 and 2006, EME had recorded wind turbine deposits of $189 million and $144 million, respectively, included in other long-term assets in its consolidated balance sheet. In addition, EME had 30 wind turbines (90 MW) in temporary storage to be used for future wind projects with remaining commitments of $3 million in 2008. At December 31, 2007, EME had recorded $84 million related to these wind turbines included in other long-term assets in its consolidated balance sheet.

At December 31, 2007, 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 currently estimated to aggregate $13 million in the next four years: $4 million each year, 2008 to 2010 and $0.4 million in 2011.

At December 31, 2007, EME and its subsidiaries were party to a long-term power purchase contract, a coal cleaning agreement, turbine operations and maintenance agreements, and agreements for the purchase of limestone and ammonia with various third parties. These minimum commitments are currently estimated to aggregate $82 million in the next five years: $19 million in 2008, $23 million in 2009, $24 million in 2010, $12 million in 2011 and $4 million in 2012.

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 continues to have obligations under the tax indemnity agreement with the former lease equity investor.

Indemnities Provided as Part of the 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 had an initial five-year term with an automatic renewal provision for subsequent one-year terms (subject to the right of either party to terminate); pursuant to the automatic renewal provision, it has been extended until February 2009. 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 207 cases for which Midwest Generation was potentially liable and that had not been settled and dismissed at December 31, 2007. Midwest Generation had recorded a $54 million and $65 million liability at December 31, 2007 and 2006, respectively, related to this matter.

Midwest Generation engaged an independent actuary in 2004 to complete an estimate of future losses. Based on the actuary's analysis, Midwest Generation recorded an undiscounted liability for its indemnity for future asbestos claims through 2045. During the fourth quarter of 2007, the actuary report was updated and the liability reduced by $9 million. In calculating future losses, the actuary made various assumptions, including but not limited to, the settlement of future claims under the supplemental agreement with Commonwealth Edison as described above, the distribution of exposure sites, and that no asbestos claims will be filed after 2044.

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 the 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, 2007 and 2006, EME had recorded a liability of $101 million and $95 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. At December 31, 2007, EME had recorded a liability of $12 million related to these matters.

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. The obligations under this indemnification agreement as of December 31, 2007, if payment were required, would be $73 million. EME has not recorded a liability related to this indemnity.

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.

Mountainview Filter Cake Indemnity

Mountainview owns and operates a power plant in Redlands, California. The plant utilizes water from on-site groundwater wells and City of Redlands (City) recycled water for cooling purposes. Unrelated to the operation of the plant, this water contains perchlorate. The pumping of the water removes perchlorate from the aquifer beneath the plant and concentrates it in the plant's wastewater treatment "filter cake." Use of this impacted groundwater for cooling purposes was mandated by Mountainview's California Energy Commission permit. Mountainview has indemnified the City for cleanup or associated actions related to groundwater contaminated by perchlorate due to the disposal of filter cake at the City's solid waste landfill. The obligations under this agreement are not limited to a specific time period or subject to a maximum liability. SCE has not recorded a liability related to this guarantee.

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.

Settlement with Illinois Attorney General

EMMT participated successfully in the first Illinois power procurement auction, held in September 2006 according to rules approved by the Illinois Commerce Commission, and entered into two load requirements services contracts through which it is delivering 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, using contracted supply from Midwest Generation.

Legal actions, including a complaint at the FERC by the Illinois Attorney General and two class action lawsuits, were instituted against successful participants in the 2006 Illinois power procurement auction, including EMMT. On July 24, 2007, Midwest Generation and EMMT, along with other power generation companies and utilities, entered into a settlement agreement with the Illinois Attorney General. Enacting legislation for the settlement was signed on August 28, 2007.

As part of the settlement, Midwest Generation agreed to pay $25 million over three years toward approximately $1 billion in utility customer rate relief and startup costs of the new Illinois Power Agency. The remainder is to be funded by subsidiaries of Exelon Corporation, subsidiaries of Ameren, Dynegy Holdings Inc., and Mid-American Energy Company. Also as part of the settlement, all auction-related complaints filed by the Illinois Attorney General at the FERC, the Illinois Commerce Commission and in the Illinois courts were dismissed and the legislature enacted a rate relief plan.

Midwest Generation made a payment of $7.5 million in September 2007 and is obligated to make monthly payments of $750,000 beginning in January 2008 and continuing until the total commitment has been funded. These payments are non-refundable; however, Midwest Generation's obligations to make the monthly payments will cease if, at any time prior to December 2009, Illinois imposes an electric rate freeze or an additional tax on generators. EME records the payments made under this agreement as an expense when paid.

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.

As of December 31, 2007, Edison International's recorded estimated minimum liability to remediate its 43 identified sites at SCE (24 sites) and EME (19 sites primarily related to Midwest Generation) was $70 million, $66 million of which was related to SCE including $31 million related to San Onofre. This remediation liability is undiscounted. Edison International's other subsidiaries have no identified remediation sites. The ultimate costs to clean up Edison International's identified sites may vary from its recorded liability due to numerous uncertainties inherent in the estimation process, such as: the extent and nature of contamination; the scarcity of reliable data for identified sites; the varying costs of alternative cleanup methods; developments resulting from investigatory studies; the possibility of identifying additional sites; and the time periods over which site remediation is expected to occur. Edison International believes that, due to these uncertainties, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $147 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 its identified sites (sites in which the upper end of the range of costs is at least $1 million), SCE also has 30 immaterial sites whose total liability ranges from $3 million (the recorded minimum liability) to $9 million. The CPUC allows SCE to recover environmental remediation costs at certain sites, representing $34 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 $64 million for its estimated minimum environmental-cleanup costs expected to be recovered through customer rates.

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

Edison International expects to clean up its identified sites over a period of up to 30 years. Remediation costs in each of the next several years are expected to range from $11 million to $31 million. Recorded costs were $25 million, $14 million and $13 million for 2007, 2006 and 2005, respectively.

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

Federal and State Income Taxes

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 certain lease and kind of lease transactions. See Note 4, for further details.

FERC Notice Regarding Investigatory Proceeding against EMMT

In 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 Energy Policy Act of 2005 and the FERC's rules regarding market behavior, all with respect to certain bidding practices previously employed by EMMT. EMMT is engaged in discussions with the staff to explore the possibility of resolution of this matter. Discussions to date have been constructive and may lead to a settlement agreement acceptable to both parties. Should these discussions not result in a settlement and a formal proceeding commenced, EMMT will be entitled to contest any alleged violations before the FERC and an appropriate court. EME believes that EMMT has complied with all applicable laws and regulations in the bidding practices that it employed, and intends to contest vigorously any allegation of violation.

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 for the years 1997 – 2003. SCE received $8 million in reliability incentive awards for the period 1997 – 2000 and applied for a reward of $5 million for 2001. For 2002, SCE's data indicated that it earned no reward and incurred no penalty. For 2003, based on the application of the PBR mechanism, it would incur a penalty of $3 million and accrued a charge for that amount in 2004. On February 28, 2005, SCE provided its final investigation report to the CPUC concluding that the reliability reporting system was 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. 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 DRA and The Utility Reform Network, filed testimony on these matters recommending various refunds and penalties be imposed on SCE. In their testimony, the various parties made refund and penalty recommendations that range up to the following amounts: refund or forgo $48 million in rewards for customer satisfaction, impose $70 million penalties for customer satisfaction, refund or forgo $35 million in rewards for employee safety, impose $35 million penalties for employee safety, impose $102 million in statutory penalties, refund $84 million related to amounts collected in rates for employee bonuses ("results sharing"), refund $4 million of miscellaneous survey expenses, and require $10 million of new employee safety programs. These recommendations total up to $388 million. On October 16, 2006, SCE filed testimony opposing the various refund and penalty recommendations of the CPSD and other intervenors.

On October 1, 2007, a POD was released ordering SCE to refund $136 million, before interest, and pay a statutory penalty of $40 million. Included in the amount to be refunded are $28 million related to customer satisfaction rewards, $20 million related to employee safety rewards, and $77 million related to results sharing. The decision requires that the proposed results sharing refund of $77 million (based on year 2000 data) be adjusted for attrition and escalation which increases the results sharing refund to $88 million. Interest as of December 31, 2007, based on amounts collected for customer satisfaction, employee safety incentives and results sharing, including escalation and attrition adjustments, would add an additional $28 million to this amount. The POD also requires SCE to forgo $35 million in rewards for which it would have otherwise been eligible. Included in the amount to be forgone is $20 million related to customer satisfaction rewards and $15 million related to employee safety rewards.

On October 31, 2007, SCE appealed the POD to the CPUC. The CPSD and an intervenor also filed appeals. The CPSD appeal requested that: (1) the statutory penalty be increased from $40 million to $83 million (2) a penalty be imposed under the PBR customer satisfaction and employee safety mechanisms in the amount of $48 million and $35 million, respectively, and (3) SCE refund/forgo rewards earned under the customer satisfaction and employee safety mechanisms of $48 million and $35 million, respectively. The appealing intervenor asked that the statutory penalty be increased to as much as $102 million. Oral argument on the appeals took place on January 30, 2008, and it is uncertain when the CPUC will issue a decision.

SCE cannot predict the outcome of the appeal. Based on SCE's proposed refunds, the combined recommendations of the CPSD and other intervenors, as well as the POD, 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 (approximately $16 million as of December 31, 2007) on collected amounts.

The system reliability component of PBR was not addressed in the POD. Pursuant to an earlier order in the case, system reliability incentives will be addressed in a second phase of the proceeding, which commenced with the filing of SCE's opening testimony in September 2007. In that testimony, SCE confirmed that its PBR system reliability results, which reflected rewards of $13 million for 1997 through 2002 and a penalty of $3 million in 2003, were valid. An indefinite suspension of the schedule for the second phase of the proceeding pending resolution of the appeals of the POD has been granted. SCE cannot predict the outcome of the second phase.

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. On March 29, 2007, the FERC issued an order agreeing with SCE's position that the charges incurred by the ISO were related to voltage support and should be allocated to the scheduling coordinators, rather than to SCE as a transmission owner. The Cities filed a request for rehearing of the FERC's order on April 27, 2007. On May 25, 2007, the FERC issued a procedural order granting the rehearing application for the limited purpose of allowing the FERC to give it further consideration. In a future order, FERC may deny the rehearing request or grant the requested relief in whole or in part. SCE believes that the most recent substantive FERC order correctly allocates responsibility for these ISO charges. However, SCE cannot predict the final outcome of the rehearing. If a subsequent regulatory decision changes the allocation of responsibility for these charges, and SCE is required to pay these charges as a transmission owner, SCE may seek recovery in its reliability service rates. SCE cannot predict whether recovery of these charges in its reliability service rates would be permitted.

Leveraged Lease Investments

Edison Capital has a net leveraged lease investment of $54 million, before deferred taxes, in three aircraft leased to American Airlines. Although American Airlines reported a profit in 2006, it 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, 2007, American Airlines was current in its lease payments to Edison Capital.

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 market 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 market, Midway-Sunset is potentially liable for refunds to purchasers in these markets.

The claims asserted against Midway-Sunset for refunds related to power sold into the PX market, 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 market 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 market on their behalves.

On December 20, 2007, Midway-Sunset entered into a settlement agreement with SCE, PG&E, SDG&E and certain California state parties to resolve Midway-Sunset's liability in the FERC refund proceedings. Midway-Sunset concurrently entered into a separate agreement with SCE and PG&E that provides for pro-rata reimbursement to Midway-Sunset by the two utilities of the portions of the agreed to refunds that are attributable to sales made by Midway-Sunset for the benefit of the utilities. The settlement has been approved by the CPUC but remains subject to approval by the FERC.

During the period in which Midway-Sunset's generation was sold into the PX market, amounts SCE received from Midway-Sunset for its pro-rata share of such sales 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.

Midwest Generation Potential Environmental Proceeding

On August 3, 2007, Midwest Generation received an NOV from the US EPA alleging that, beginning in the early 1990's and into 2003, Midwest Generation or Commonwealth Edison performed repair or replacement projects at six Illinois coal-fired electric generating stations in violation of the Prevention of Significant Deterioration requirements and of the New Source Performance Standards of the CAA, including alleged requirements to obtain a construction permit and to install best available control technology at the time of the projects. The US EPA also alleges that Midwest Generation and Commonwealth Edison violated certain operating permit requirements under Title V of the CAA. Finally, the US EPA alleges violations of certain opacity and particulate matter standards at the Illinois Plants. The NOV does not specify the penalties or other relief that the US EPA seeks for the alleged violations. Midwest Generation, Commonwealth Edison, the US EPA, and the DOJ are in talks designed to explore the possibility of a settlement. If the settlement talks fail and the DOJ files suit, litigation could take many years to resolve the issues alleged in the NOV. As a result, Midwest Generation is investigating the claims made by the US EPA in the NOV and has identified several defenses which it will raise if the government files suit. At this early stage in the process, Midwest Generation cannot predict the outcome of this matter or estimate the impact on its facilities, its results of operations or financial position.

On August 13, 2007, Midwest Generation and Commonwealth Edison received a letter signed by several Chicago-based environmental action groups stating that, in light of the NOV, the groups are examining the possibility of filing a citizen suit against Midwest Generation and Commonwealth Edison based presumably on the same or similar theories advanced by the US EPA in the NOV.

By letter dated August 8, 2007, Commonwealth Edison advised EME that Commonwealth Edison believes it is entitled to indemnification for all liabilities, costs, and expenses that it may be required to bear as a result of the NOV. By letter dated August 16, 2007, Commonwealth Edison tendered a request for indemnification to EME for all liabilities, costs, and expenses that Commonwealth Edison may be required to bear if the environmental groups were to file suit. Midwest Generation and Commonwealth Edison are cooperating with one another in responding to the NOV.

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 March 2001, the Hopi Tribe was permitted to intervene as an additional plaintiff. In April 2004, the District Court denied 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. In September 2007, the Federal Circuit reversed a lower court decision on remand in the related lawsuit, finding that the U.S. Government had breached its trust obligation in connection with the setting of the royalty rate for the coal supplied to Mohave. Subsequently, the Federal Circuit denied the U.S. Government's petition for rehearing. The U.S. Government may, however, still seek review by the Supreme Court of the Federal Circuit's September decision.

Pursuant to a joint request of the parties, the District Court granted a stay of the action in October 2004 to allow the parties to attempt to negotiate a resolution of the issues associated with Mohave with the assistance of a facilitator. In a joint status report filed on November 9, 2007, the parties informed the court that their mediation efforts had terminated and subsequently filed a joint motion to lift the stay. The parties have also filed recommendations for a scheduling order to govern the anticipated resumption of litigation. The Court has not yet ruled on either the motion to lift the stay or the scheduling recommendations, but has scheduled a status hearing for March 6, 2008. SCE cannot predict the outcome of the Navajo Nation's and Hopi Tribe's complaints against SCE or the ultimate impact on these complaints of the Supreme Court's 2003 decision and the on-going litigation by the Navajo Nation against the U.S. Government in the related case.

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 $46 million per year. Insurance premiums are charged to operating expense.

Palo Verde Nuclear Generating Station Outage and Inspection

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 reduction in the ability to cool water before returning it to the plant. The second inspection identified five violations, but none of those resulted in increased NRC scrutiny. The third 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 based on the outcome of completed surveys of its plant personnel and self-assessments of its programs and procedures. These corrective actions are currently being developed in conjunction with the NRC, and are forecast to be completed and embodied in an NRC Confirmatory Order by the end of February 2008. These corrective actions will increase costs to both Palo Verde and its co-owners, including SCE. SCE cannot calculate the total increase in costs until the corrective actions are finalized and the NRC issues the Confirmatory Order. The operation and maintenance costs (including overhead) increased in 2007 by approximately $7 million from 2006. SCE presently estimates that operation and maintenance costs will increase by approximately $23 million (nominal) over the two year period 2008 – 2009, from 2007 recorded costs including overhead costs. SCE also is unable to estimate how long SCE will continue to incur these costs.

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.

In March 2007, SCE successfully challenged the CPUC's calculation of SCE's annual targets. This change is expected to enable SCE to meet its target for 2007. On April 3, 2007, SCE filed its renewable portfolio standard compliance report for 2004 through 2006. The compliance report confirms that SCE met its renewable goals for each of these years. In light of the annual target revisions that resulted from the March 2007 successful challenge to the CPUC's calculation, the report also projects that SCE will meet its renewable goals for 2007 and 2008 but could have a potential deficit in 2009. The potential deficit in 2009, however, does not take into account future procurement opportunities or the full utilization by SCE of the CPUC's rules for flexible compliance with annual targets. It is unlikely that SCE will have 20% of its annual electricity sales procured from renewable resources by 2010. However, SCE may still meet the 20% target by utilizing the flexible compliance rules.

SCE is scheduled to update the compliance report discussed above in March 2008, and currently anticipates demonstrating full compliance for the procurement year 2007 as well as forecasting full compliance, with the use of flexible compliance rules, for the procurement year 2008. SCE continues to engage in several renewable procurement activities including formal solicitations approved by the CPUC, bilateral negotiations with individual projects and other initiatives.

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 and line loss charges incurred by SCE on the DWP's behalf. The scheduling coordinator charges had been billed to the DWP under a FERC tariff that was 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.

In January 2008, an agreement between SCE and the DWP was executed settling the dispute discussed above. The settlement had been previously approved by the FERC in July 2007. The settlement agreement provides that the DWP will be responsible for line losses and SCE would be responsible for the scheduling coordinator charges. During the fourth quarter of 2007, SCE reversed and recognized in earnings (under the caption "Purchased power " in the consolidated statements of income) $30 million of an accrued liability representing line losses previously collected from the DWP that were subject to refund. As of December 31, 2007, SCE had an accrued liability of approximately $22 million (including $3 million of interest) representing the estimated amount SCE will refund for scheduling coordinator charges previously collected from the DWP. SCE made its first refund payment on February 20, 2008 and the second refund payment is due on March 15, 2008. SCE previously received FERC-approval to recover the scheduling coordinator charges from all transmission grid customers through SCE's transmission rates and on December 11, 2007 the FERC accepted SCE's proposed transmission rates reflecting the forecast levels of costs associated with the settlement. Upon signing of the agreement in January 2008, SCE recorded a regulatory asset and recognized in earnings the amount of scheduling coordinator charges to be collected through rates.

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 was filed on February 22, 2008, 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 and some of Unit 2's spent fuel is stored. SCE, as operating agent, plans to transfer fuel from the Unit 2 and 3 spent fuel pools to the independent storage installation on an as-needed basis to maintain full core off-load capability for Units 2 and 3. There are now sufficient dry casks and modules available at the independent spent fuel storage installation to meet plant requirements through 2008. SCE plans to add storage capacity incrementally to meet the plant requirements 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 add storage capacity incrementally 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:

	Unrealized Gain (Loss) on Cash Flow Hedges	Foreign Currency Translation Adjustment	Minimum Pension Liability Adjustment	Pension and PBOP— Net Loss	Pension and PBOP— Prior Service Cost	Accumulated Other Comprehensive Income (Loss)
Balance at December 31, 2005	$ (216)	$ 2	$ (12)	$	$	$ (226)
Change for 2006	326	(1)				325
SFAS No. 158 adjustments			12	(37)	4	(21)
Balance at December 31, 2006	110	1	—	(37)	4	78
Change for 2007	(170)	(2)		3	(1)	(170)
Balance at December 31, 2007	**$ (60)**	**$ (1)**	**$ —**	**$ (34)**	**$ 3**	**$ (92)**

SFAS No. 158 — postretirement benefits is discussed in "Pension Plans and Postretirement Benefits Other Than Pensions" in Note 5.

Unrealized losses on cash flow hedges, net of tax, at December 31, 2007, included unrealized losses on commodity hedges related to Midwest Generation and EME Homer City futures and forward electricity contracts that qualify for hedge accounting. These losses arise because current forecasts of future electricity prices in these markets are greater than the contract prices. As EME's hedged positions for continuing operations are realized, approximately $3 million, after tax, of the net unrealized losses on cash flow hedges at December 31, 2007 are expected to be reclassified into earnings during the next 12 months. Management expects that reclassification of net unrealized losses will decrease 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 a cash flow hedge is designated is through December 31, 2010.

Under SFAS No. 133, the portion of a cash flow hedge that does not offset the change in value of the transaction being hedged, which is commonly referred to as the ineffective portion, is immediately recognized in earnings. EME recorded net losses of approximately $41 million, $6 million and $65 million in 2007, 2006 and 2005, respectively, representing the amount of cash flow hedges' ineffectiveness for continuing operations, reflected in operating revenues in Edison International's consolidated income statements.

Note 8. Property and Plant

Nonutility Property

Nonutility property included on the consolidated balance sheets is composed of:

In millions December 31,	2007	2006
Furniture and equipment	**$ 90**	$ 107
Building, plant and equipment	**4,490**	4,026
Land (including easements)	**85**	78
Emission allowances	**1,305**	1,305
Leasehold improvements	**110**	100
Construction in progress	**591**	367
	6,671	5,983
Accumulated provision for depreciation	**(1,765)**	(1,627)
Nonutility property – net	**$ 4,906**	$ 4,356

The power sales agreements of certain wind projects qualify as operating leases under EITF No. 01-8, and SFAS No. 13, Accounting for Leases. The carrying amount and related accumulated depreciation of the property of these wind projects totaled $559 million and $28 million, respectively, at December 31, 2007. EME records rental income from wind projects that are accounted for as operating leases as electricity is delivered at rates defined in power sales agreements. Revenue from these power sales agreements were $24 million in 2007 and $10 million in 2006.

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. The fair value of the nuclear decommissioning trusts was $3.4 billion at December 31, 2007. 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	2007	2006	2005
Beginning balance	**$ 2,759**	$ 2,628	$ 2,188
Accretion expense	**169**	160	366
Revisions	**3**	—	117
Liabilities added	**7**	42	16
Liabilities settled	**(46)**	(71)	(59)
Ending balance	**$ 2,892**	$ 2,759	$ 2,628

The ARO liability as of December 31, 2007 includes an ARO liability of $2.8 billion related to nuclear decommissioning.

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,	2007	2006	2005
Cash payments for interest and taxes:			
Interest — net of amounts capitalized	**$ 709**	$ 739	$ 776
Tax payments — net	**$ 332**	$ 826	$ 185
Noncash investing and financing activities:			
Details of debt exchange:			
Pollution-control bonds redeemed	**$ —**	$ (331)	$ (452)
Pollution-control bonds issued	**$ —**	$ 331	$ 452
Details of capital lease obligations:			
Capital lease purchased	**$ (10)**	$ —	$ (15)
Capital lease obligation issued	**$ 10**	$ —	$ 15
Dividends declared but not paid			
Common Stock	**$ 99**	$ 94	$ 88
Preferred and preference stock of utility not subject to mandatory redemption	**$ 13**	$ 9	$ 10
Details of assets acquired:			
Fair value of assets acquired	**$ 41**	$ 29	$ 154
Liabilities assumed	**$ —**	$ —	$ —
Net assets acquired	**$ 41**	$ 29	$ 154
Details of consolidation of variable interest entities:			
Assets	**$ 12**	$ 18	$ 37
Liabilities	**$ (5)**	$ (4)	$ (27)

In connection with certain wind projects acquired during the years ended December 31, 2007 and 2006, the purchase price included payments that were due upon the start and completion of construction. Accordingly, EME accrued for estimated payments related to wind projects primarily due upon completion of construction scheduled during 2008 and made payments primarily related to wind projects completed during 2007.

During the year ended December 31, 2006, EME received a capital contribution of $76 million in the form of ownership interests in a portfolio of wind projects and a small biomass project. See Note 18 for further discussion of acquisitions and dispositions.

During the year ended December 31, 2005, EME received a capital contribution of $20 million from its parent for investments in an entity which was previously owned by EME's affiliate, Edison Capital. This entity holds interests in various wind projects.

Note 10. Fair Values of Financial Instruments

The carrying amounts and fair values of financial instruments are:

	December 31,			
	2007		2006	
In millions	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Derivatives:				
Interest rate hedges	**$ (33)**	**$ (33)**	$ —	$ —
Foreign currency hedge	**3**	**3**	5	5
Commodity price assets	**82**	**82**	234	234
Commodity price liabilities	**(214)**	**(214)**	(160)	(160)
Other:				
Decommissioning trusts	**3,378**	**3,378**	3,184	3,184
QF power contracts liabilities	**(3)**	**(3)**	(2)	(2)
Long-term debt	**(9,016)**	**(8,995)**	(9,101)	(9,607)
Long-term debt due within one year	**(18)**	**(18)**	(488)	(488)
Trading Activities:				
Assets	**141**	**141**	318	318
Liabilities	**(9)**	**(9)**	(207)	(207)

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; and quoted market prices for decommissioning trusts.

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.

In January and February 2008, SCE settled interest rate-locks resulting in realized losses of $33 million. A related regulatory asset was recorded in this amount and SCE expects to amortize and recover this amount as interest expense associated with its 2008 financings.

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,	2007	2006
Current:		
Regulatory balancing accounts	**$ 99**	$ 128
Rate reduction notes – transition cost deferral	**—**	219
Direct access procurement charges	**—**	63
Energy derivatives	**71**	88
Purchased-power settlements	**8**	31
Deferred FTR proceeds	**15**	14
Other	**4**	11
	$ 197	$ 554
Long-term:		
Regulatory balancing accounts	**15**	—
Flow-through taxes – net	**1,110**	1,023
Unamortized nuclear investment – net	**405**	435
Nuclear-related ARO investment – net	**297**	317
Unamortized coal plant investment – net	**94**	102
Unamortized loss on reacquired debt	**331**	318
SFAS No. 158 pensions and other postretirement benefits	**231**	303
Energy derivatives	**70**	145
Environmental remediation	**64**	77
Other	**104**	98
	$ 2,721	$ 2,818
Total Regulatory Assets	**$ 2,918**	$ 3,372

SCE's regulatory asset related to the rate reduction bonds is amortized simultaneously with the amortization of the rate reduction bonds liability, and was recovered in 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 were collected as of September 30, 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 October 2008. SCE's regulatory assets related to deferred FTR proceeds represent the deferral of congestion revenue SCE received as a transmission owner from the annual ISO FTR auction. The deferred FTR proceeds will be recognized through March 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 related to San Onofre are expected to be recovered by 2022. SCE's nuclear-related regulatory assets related to Palo Verde are expected to be recovered by 2027. 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 30 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.

In 2007, SCE earned 8.77% return on both of the regulatory assets listed above: unamortized nuclear investment – net and unamortized coal plant investment – net.

Regulatory Liabilities

Regulatory liabilities included on the consolidated balance sheets are:

In millions December 31,	2007	2006
Current:		
Regulatory balancing accounts	**$ 967**	$ 912
Rate reduction notes – transition cost overcollection	**20**	—
Direct access procurement charges	**—**	63
Energy derivatives	**10**	7
Deferred FTR costs	**19**	11
Other	**3**	7
	$ 1,019	$ 1,000
Long-term:		
ARO	**793**	732
Costs of removal	**2,230**	2,158
SFAS No. 158 pensions and other postretirement benefits	**308**	145
Energy derivatives	**27**	27
Employee benefit plans	**75**	78
	$ 3,433	$ 3,140
Total Regulatory Liabilities	**$ 4,452**	$ 4,140

Rate reduction notes – transition cost overcollection represents the nonbypassable rates being charged to customers subsequent to the final principal payment made in December 2007. 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 liabilities related to deferred FTR costs represent the deferral of the costs associated with FTRs that SCE purchased during the annual ISO auction process. The FTRs provide SCE with scheduling priority in certain transmission grid congestion areas in the day-ahead market. The FTRs meet the definition of a derivative instrument and are recorded at fair value and marked to market each reporting period. Any fair value change for FTRs is reflected in the deferred FTR costs regulatory liability. The deferred FTR costs are recognized as FTRs are used or expire in various periods through March 2008. 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, 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. All the amounts will be refunded to ratepayers. (see "Long-Term Debt" discussion in Note 3 for further detail).

Note 12. Other Nonoperating Income and Deductions

Other nonoperating income and deductions are as follows:

In millions **Year ended December 31,**	**2007**	**2006**	**2005**
AFUDC	**$ 46**	$ 32	$ 25
Increase in cash surrender value of life insurance policies	**23**	21	18
Performance-based incentive awards	**4**	19	33
Demand-side management and energy efficiency performance incentives	**—**	—	45
Other	**16**	13	6
Total utility nonoperating income	**$ 89**	$ 85	$ 127
Nonutility nonoperating income	**6**	48	9
Total other nonoperating income	**$ 95**	$ 133	$ 136
Various penalties	**$ 5**	$ 23	$ 27
Other	**40**	37	38
Total utility nonoperating deductions	**$ 45**	$ 60	$ 65
Nonutility nonoperating deductions	**—**	3	2
Total other nonoperating deductions	**$ 45**	$ 63	$ 67

In 2006, nonutility nonoperating income primarily reflects Edison Capital's $19 million pre-tax gain on the sale of certain investments, including Edison Capital's interest in an affordable housing project, 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.

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.

The following is SCE's investment in each project as of December 31, 2007:

In millions	Investment in Facility	Accumulated Depreciation and Amortization	Ownership Interest
Transmission systems:			
Eldorado	$ 71	$ 12	60%
Pacific Intertie	308	96	50
Generating stations:			
Four Corners Units 4 and 5(coal)	529	435	48
Mohave (coal)	344	283	56
Palo Verde (nuclear)	1,800	1,490	16
San Onofre (nuclear)	4,722	4,001	78
Total	**$ 7,774**	**$ 6,317**	

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. 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 consolidate these four projects.

The book value of the projects' plant assets (recorded in nonutility property) is $300 million at December 31, 2007 and $319 million at December 31, 2006.

Project	Capacity	Termination Date[1]	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%

(1) SCE's power purchase agreements with Sycamore and Watson expired on December 31, 2007. Discussions on extending the power purchase and steam agreements are underway, but no assurance can be given that such discussions will lead to extensions of these agreements. As of January 1, 2008, these projects sell power to SCE under agreements with pricing set by the CPUC.

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.

Edison Capital has investments in affordable housing projects that are variable interests. These projects are funded with nonrecourse debt totaling $14 million at December 31, 2007. Properties serving as collateral for these loans had a carrying value of $14 million and are classified as nonutility property on the December 31, 2007 consolidated balance sheet. The creditors to these projects do not have recourse to the general credit of Edison Capital.

Effective March 31, 2004, three wind projects were consolidated and at December 31, 2005, two additional wind projects were consolidated in accordance with FIN 46(R). These projects were funded with nonrecourse debt totaling $24 million at December 31, 2007. Properties serving as collateral for these loans had a carrying value of $53 million and are classified as property, plant and equipment on Edison International's consolidated balance sheet at December 31, 2007.

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, 2007, EME had a 50% ownership interest in the project and its investment was $127 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 $16 million and recapture of tax credits.

Entities with Unavailable Financial Information

SCE also has eight other contracts with QFs that contain variable pricing provisions based on the price of natural gas and are potential VIEs under FIN 46(R). SCE might be considered to be the consolidating entity under this standard. SCE continues to attempt to obtain information for these projects in order to determine whether the projects should be consolidated by SCE. These entities are not legally obligated to provide the financial information to SCE and have declined to provide any financial information to SCE. Under the grandfather scope provisions of FIN 46(R), SCE is not required to apply this rule to these entities as long as SCE continues to be unable to obtain this information. The aggregate capacity dedicated to SCE for these projects is 267 MW. SCE paid $180 million in both 2007 and 2006 and $198 million in 2005 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 years ended December 31, 2007, 2006 and 2005. In January 2008, SCE repurchased 350,000 shares of 4.08% cumulative preferred stock at a price of $19.50 per share. SCE retired this preferred stock in January 2008 and recorded a $2 million gain on the cancellation of reacquired capital stock (reflected in the caption "Common stock" on the consolidated balance sheets). There is no sinking fund requirement for redemptions or repurchases of preferred stock.

SCE's preferred and preference stock not subject to mandatory redemption is:

Dollars in millions, except per-share amounts	December 31, Shares Outstanding	December 31, Redemption Price	2007	2006
Cumulative preferred stock				
$25 par value:				
4.08% Series	1,000,000	$ 25.50	**$ 25**	$ 25
4.24% Series	1,200,000	$ 25.80	**30**	30
4.32% Series	1,653,429	$ 28.75	**41**	41
4.78% Series	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**	200
			$ 929	$ 929
Less issuance costs			**(14)**	(14)
Total			**$ 915**	$ 915

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, 2007, accrued dividends related to SCE's preferred and preference stock not subject to mandatory redemption were $13 million.

Note 16. Business Segments

Edison International's reportable business segments include its electric utility operation segment (SCE), a nonutility power generation segment (EME), and a financial services provider segment (Edison Capital). Included in the nonutility power generation segment are the activities of MEHC, the holding company of EME. MEHC's only substantive activities were its obligations under the senior secured notes which were paid in full on June 25, 2007 as discussed in Note 3. MEHC does not have any substantive operations. Edison International evaluates performance based on net income.

SCE is a rate-regulated electric utility that supplies electric energy to a 50,000 square-mile area of central, coastal and Southern California. SCE also produces electricity. EME is engaged in the business of developing, acquiring, owning or leasing, operating and selling energy and capacity from electric power generation facilities. EME 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 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 and included in the financial services segment.

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 were 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'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 51%, 58% and 69% of nonutility power generation revenues for the years ended December 31, 2007, 2006 and 2005, respectively. 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 non-investment grade companies. Any losses due to a PJM member default are shared by all other members based upon a predetermined formula. At December 31, 2007, EME's account receivable due from PJM was $82 million.

Beginning in January 2007, EME also derived a significant source of its revenues from the sale of energy, capacity and ancillary services generated at the Illinois Plants to Commonwealth Edison under load requirements services contracts. Sales under these contracts accounted for 19% of EME's consolidated operating revenues for the year ended December 31, 2007. Commonwealth Edison's senior unsecured debt rating was downgraded below investment grade by S&P in June 2007 and by Moody's in March 2007. As a result, Commonwealth Edison is required to pay EME twice a month for sales under these contracts. At December 31, 2007, EME's account receivable due from Commonwealth Edison was $20 million.

Reportable Segments Information

The following is information (including the elimination of intercompany transactions) related to Edison International's reportable segments:

In millions	Electric Utility	Nonutility Power Generation	Financial Services	All Others[1]	Edison International
2007					
Operating revenue	$ 10,476	$ 2,575	$ 56	$ 6	$ 13,113
Depreciation, decommissioning and amortization	1,094	161	9	—	1,264
Interest and dividend income	39	96	15	4	154
Equity in income from partnerships and unconsolidated subsidiaries – net	—	51	28	—	79
Interest expense – net of amounts capitalized	429	309	10	4	752
Income tax expense (benefit) – continuing operations	337	173	4	(22)	492
Income (loss) from continuing operations	707	342	69	(18)	1,100
Net income (loss)	707[2]	340	69	(18)	1,098
Total assets	27,449	7,054	2,820	239	37,562
Capital expenditures	2,286	540	—	—	2,826
2006					
Operating revenue	$ 10,312	$ 2,232	$ 73	$ 5	$ 12,622
Depreciation, decommissioning and amortization	1,026	143	13	(1)	1,181
Interest and dividend 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 and dividend 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

(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 $(2) million for 2007, $98 million for 2006 and $29 million for 2005.

Geographic Information

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

In millions Year Ended December 31,	2007	2006	2005
Revenue			
United States	**$ 13,061**	$ 12,563	$ 11,789
International	**52**	59	63
Total	**$ 13,113**	$ 12,622	$ 11,852

In millions December 31,	2007	2006
Assets		
United States	**$ 35,237**	$ 33,965
International	**2,325**	2,296
Assets of discontinued operations	**—**	—
Total	**$ 37,562**	$ 36,261

Note 17. 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, by and between EME and IPM for approximately $20 million. EME recorded an impairment charge of approximately $5 million during the fourth quarter of 2004 related to the planned disposition of this investment. 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 CBK project pursuant to a Purchase Agreement, dated November 5, 2004, by and between EME and Corporacion IMPSA S.A. 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.

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 the project's 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 £5 million (approximately $10 million) in 2007. The after-tax income attributable to the Lakeland project was $6 million, $85 million and $24 million for 2007, 2006 and 2005, respectively. 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 2007, 2006 or 2005. The pre-tax earnings (loss) from discontinued operations were $3 million in 2007, $118 million in 2006 and $(20) million in 2005. The pre-tax loss from discontinued operations in 2005 included a $9 million gain on sale before taxes.

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, 2007 and 2006.

Note 18. 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 Wildorado Wind, L.P., 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. This project started construction in April 2006 and commenced commercial operation during April 2007. 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 property, plant and equipment 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 $156.5 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 property, plant and equipment in EME'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.

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.

Note 19. 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, 2007 and 2006. 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,	2007	2006	2005
Income from leveraged leases	**$ 50**	$ 67	$ 71
Tax effect of pre-tax income:			
Current	**26**	41	45
Deferred	**(43)**	(66)	(72)
Total tax expense	**(17)**	(25)	(27)
Net income from leveraged leases	**$ 33**	$ 42	$ 44

The net investment in leveraged leases is:

In millions December 31,	2007	2006
Rentals receivable — net	**$ 3,297**	$ 3,411
Estimated residual value	**42**	42
Unearned income	**(866)**	(958)
Investment in leveraged leases	**2,473**	2,495
Deferred income taxes	**(2,316)**	(2,268)
Net investment in leveraged leases	**$ 157**	$ 227

Rental receivables are net of principal and interest on nonrecourse debt, credit reserves and the current portion of rentals receivable. Credit reserves were $5 million and $10 million at December 31, 2007 and 2006, respectively. The current portion of rentals receivable was $74 million and $36 million at December 31, 2007 and 2006, 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.

The difference between the carrying value of these equity investments and the underlying equity in the net assets was $13 million at December 31, 2007. 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,	2007	2006	2005
Revenue	**$ 581**	$ 707	$ 717
Expenses	**552**	676	745
Net income (loss)	**$ 29**	$ 31	$ (28)

		Edison International	
In millions	**December 31,**	**2007**	2006
Current assets		**$ 305**	$ 372
Other assets		**3,187**	3,864
Total assets		**$ 3,492**	$ 4,236
Current liabilities		**$ 190**	$ 247
Other liabilities		**1,890**	2,170
Equity		**1,412**	1,819
Total liabilities and equity		**$ 3,492**	$ 4,236

The undistributed earnings of equity method investments were $7 million in 2007 and $8 million in 2006.

Impairment Loss on Equity Method Investment

In 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 in 2005.

Note 20. Quarterly Financial Data (Unaudited)

	2007				
In millions, except per-share amounts	**Total**	**Fourth**	**Third**	**Second**	**First**
Operating revenue	$ 13,113	$ 3,211	$ 3,942	$ 3,047	$ 2,912
Operating income	2,509	481	898	501	627
Income from continuing operations	1,100	214	465	91	330
Income (loss) from discontinued operations – net	(2)	(3)	(4)	2	3
Cumulative effect of accounting change – net	—	—	—	—	—
Net income	1,098	211	461	93	333
Basic earnings (loss) per share:					
Continuing operations	3.34	0.65	1.41	0.28	1.00
Discontinued operations	(0.01)	(0.01)	(0.01)	0.01	0.01
Total	3.33	0.64	1.40	0.29	1.01
Diluted earnings (loss) per share:					
Continuing operations	3.32	0.65	1.40	0.28	1.00
Discontinued operations	(0.01)	(0.01)	(0.01)	—	0.01
Total	3.31	0.64	1.39	0.28	1.01
Dividends declared per share	1.175	0.305	0.29	0.29	0.29
Common stock prices:					
High	60.26	58.55	59.57	60.26	51.00
Low	42.76	53.14	50.64	49.13	42.76
Close	53.37	53.37	55.45	56.12	49.13

	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	3.27	0.80	1.39	0.53	0.56
Discontinued operations	0.30	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

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

Dollars in millions, except per-share amounts	2007	2006	2005	2004	2003
Edison International and Subsidiaries					
Operating revenue	**$ 13,113**	$ 12,622	$ 11,852	$ 10,199	$ 10,732
Operating expenses	**$ 10,604**	$ 10,132	$ 9,539	$ 9,099	$ 9,277
Income from continuing operations	**$ 1,100**	$ 1,083	$ 1,108	$ 226	$ 655
Net income	**$ 1,098**	$ 1,181	$ 1,137	$ 916	$ 821
Weighted-average shares of common stock outstanding (in millions)	**326**	326	326	326	326
Basic earnings (loss) per share:					
Continuing operations	**$ 3.34**	$ 3.28	$ 3.38	$ 0.69	$ 2.01
Discontinued operations	**$ (0.01)**	$ 0.30	$ 0.09	$ 2.12	$ 0.54
Cumulative effect of accounting change	**$ —**	$ —	$ —	$ —	$ (0.03)
Total	**$ 3.33**	$ 3.58	$ 3.47	$ 2.81	$ 2.52
Diluted earnings per share	**$ 3.31**	$ 3.57	$ 3.45	$ 2.77	$ 2.50
Dividends declared per share	**$ 1.175**	$ 1.10	$ 1.02	$ 0.85	$ 0.20
Book value per share at year-end	**$ 25.92**	$ 23.66	$ 20.30	$ 18.56	$ 16.52
Market value per share at year-end	**$ 53.37**	$ 45.48	$ 43.61	$ 32.03	$ 21.93
Rate of return on common equity	**13.6%**	16.5%	18.1%	17.1%	17.1%
Price/earnings ratio	**16.0%**	12.7	12.6	11.4	8.7
Ratio of earnings to fixed charges	**2.45**	2.48	2.49	1.11	1.58
Total assets	**$ 37,562**	$ 36,261	$ 34,791	$ 33,269	$ 38,267
Long-term debt	**$ 9,016**	$ 9,101	$ 8,833	$ 9,678	$ 9,220
Common shareholders' equity	**$ 8,444**	$ 7,709	$ 6,615	$ 6,049	$ 5,383
Preferred stock subject to mandatory redemption	**$ —**	$ —	$ —	$ 139	$ 141
Retained earnings	**$ 6,311**	$ 5,551	$ 4,798	$ 4,078	$ 3,466
Southern California Edison Company					
Operating revenue	**$ 10,478**	$ 10,312	$ 9,500	$ 8,448	$ 8,854
Net income available for common stock	**$ 707**	$ 776	$ 725	$ 915	$ 922
Basic earnings per Edison International common share	**$ 2.17**	$ 2.38	$ 2.22	$ 2.81	$ 2.83
Total assets	**$ 27,480**	$ 26,110	$ 24,703	$ 23,290	$ 21,771
Rate of return on common equity	**12.0%**	15.0%	15.3%	21.0%	20.2%
Edison Mission Energy					
Revenue	**$ 2,580**	$ 2,239	$ 2,265	$ 1,653	$ 1,779
Income (loss) from continuing operations	**$ 416**	$ 316	$ 414	$ (560)	$ (96)
Net income	**$ 414**	$ 414	$ 442	$ 130	$ 19
Total assets	**$ 7,308**	$ 7,250	$ 7,023	$ 7,087	$ 12,299
Rate of return on common equity	**18.4%**	18.4%	24.2%	7.0%	1.0%
Edison Capital					
Revenue	**$ 56**	$ 73	$ 77	$ 87	$ 86
Net income	**$ 69**	$ 89	$ 81	$ 52	$ 58
Total assets	**$ 2,977**	$ 3,199	$ 3,376	$ 3,279	$ 3,196
Rate of return on common equity	**15.6%**	9.6%	12.3%	8.1%	7.9%

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. Prior to 2007, the above table included MEHC. Because MEHC paid off its long-term debt in 2007, it no longer files with the SEC. Therefore, beginning with 2007, the above table includes Edison Mission Energy data. Amounts presented in this table have been restated to reflect Edison Capital's capital contribution to MEHC. See Note 16 for further discussion. During 2004, EME sold 11 international projects. During 2003, SCE sold certain oil storage and pipeline facilities. Amounts presented in this table have been restated to reflect continuing operations unless stated otherwise. See Note 17, Discontinued Operations, for further discussion.

Board of Directors

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President and
Chief Executive Officer,
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A director since 1990[†]

Vanessa C.L. Chang [1,4]
Principal,
EL & EL Investments
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Theodore F. Craver, Jr.*
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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 [1,4,5]
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 & 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
Retired Chief Executive Officer,
Pacific Life Insurance Company
Newport Beach, California
A director since 1995

Brett White [2]
President and
Chief Executive Officer
CB Richard Ellis
(commercial real estate services company)
Los Angeles, California
A director since 2007

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

* Service includes Edison International board only. All other directors are members of both Edison International and Southern California Edison boards.

† 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

Diane L. Featherstone
Senior Vice President,
Human Resources

Cecil R. House
Senior Vice President,
Safety, Operations Support
and Chief Procurement Officer

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

Scott S. Cunningham
Vice President,
Investor Relations

Barbara E. Mathews
Vice President, Associate General Counsel,
Chief Governance Officer and Corporate
Secretary

Megan Scott-Kakures
Vice President and
General Auditor

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

Linda G. Sullivan
Vice President and
Controller

Southern California Edison Company

Alan J. Fohrer
Chairman and Chief Executive Officer

John R. Fielder
President

Polly L. Gault
Executive Vice President,
Public Affairs

Diane L. Featherstone
Senior Vice President,
Human Resources

Bruce C. Foster
Senior Vice President,
Regulatory Affairs

Cecil R. House
Senior Vice President,
Safety, Operations Support and
Chief Procurement Officer

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

Lisa D. Cagnolatti
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

Erwin G. Furukawa
Vice President,
Customer Programs and Services

Stuart R. Hemphill
Vice President,
Renewable and Alternative Power

Harry B. Hutchison
Vice President,
Customer Service Operations

Akbar Jazayeri
Vice President,
Regulatory Operations

Walter J. Johnston
Vice President,
Power Delivery

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

Ross T. Ridenoure
Vice President and Site Manager,
San Onofre Nuclear Generating Station

Tommy Ross
Vice President,
Public Affairs

Megan Scott-Kakures
Vice President and General Auditor

Leslie E. Starck
Vice President,
Local Public Affairs

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

Linda G. Sullivan
Vice President and Controller

Edison Mission Group*

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

Steven D. Eisenberg
Senior Vice President and General Counsel

John P. Finneran, Jr.
Senior Vice President,
Business Management

Guy F. Gorney
Senior Vice President,
Generation

Paul Jacob
Senior Vice President,
Marketing and Trading

Gerard P. Loughman
Senior Vice President,
Development

Douglas R. McFarlan
Senior Vice President,
Public Affairs and Communications

W. James Scilacci
Senior Vice President and
Chief Financial Officer

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 24, 2008, 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®

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