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102-05168-SAB/TNW/CJJ
October 26, 2004

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Mail Station P1-37
Washington, DC 20555-0001

Dear Sirs:

Subject: Palo Verde Nuclear Generating Station (PVNGS)
Units 1, 2, & 3
Docket Nos. STN 50-528/529/530
Submittal of 2003 Annual Financial Reports

10 CFR 50.71(b) requires each power production licensee to submit its financial report, including certified financial statements, to the Commission upon issuance of the report. Palo Verde Nuclear Generating Station (PVNGS) Units 1, 2, and 3 have seven joint licensees who issue their annual financial reports at different times through the year. In order to meet the 10 CFR 50.71(b) requirement, Arizona Public Service Company (APS), the operator of PVNGS Units 1, 2, and 3, compiles the annual financial reports from the seven joint owners of the PVNGS Units and submits them to the Commission all at one time.

Enclosed please find a CD containing each of the 2003 Annual Financial Reports for the Participants who jointly own PVNGS. These Participants are Arizona Public Service Company, Salt River Project, El Paso Electric Company, Southern California Edison Company, Public Service Company of New Mexico, Southern California Public Power Authority, and Los Angeles Department of Water and Power

No commitments are being made to the NRC by this letter. Should you have any questions, please contact Thomas N. Weber at (623) 393-5764.

Sincerely,

SAB/TNW/CJJ

Enclosure - CD

cc: B. S. Mallett (all w/o enclosure)
M. B. Fields
N. L Salgado

M004

ENCLOSURE (CD)

PALO VERDE NUCLEAR GENERATING STATION

2003 ANNUAL FINANCIAL REPORTS

CD Contact Information

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Document Components

A total of one CD is included in this submission. The CD-ROM labeled "PVNGS 2003 Annual Financial Reports," contains the following nine (9) files:

001	Edison_2003_Annual_Report.pdf	9,380 KB	publicly available
002	Elpaso_2003_Annual_Report.pdf	539 KB	publicly available
003	ladwp_energy_2003_Annual_Report.pdf	311 KB	publicly available
004	ladwp_water_2003_Annual_Report.pdf	259 KB	publicly available
005	PNM_2003_Annual_Report.pdf	4,445 KB	publicly available
006	PNW_2003_Annual_Report.pdf	3,365 KB	publicly available
007	SCE_2003_Annual_Report.pdf	5,228 KB	publicly available
008	SCPPA_2003_Annual_Report.pdf	1,056 KB	publicly available
009	SR_2003_Annual_Report.pdf	975 KB	publicly available

EDISON INTERNATIONAL®

2003 Annual Report

THE PEOPLE OF
EDISON INTERNATIONAL:

Hold integrity as our paramount value

Commit to excellence

Respect each other and the people
with whom we deal

These personal values we hold
and the customer value we deliver
are essential to create shareholder value.

DEAR FELLOW SHAREHOLDERS:

We have traveled some rough roads together in recent times. It gives me great pleasure to confirm that 2003 was a year of outstanding progress at Edison International. In talking about how far we have come, and where we are going, I want to tell you about the principal elements of that progress. I also want to give you some sense of the largest issues that lie immediately ahead.

EDISON INTERNATIONAL IN 2003 — A BRIEF OVERVIEW

This past year was remarkable from several perspectives. It marked the successful completion of the company's highest priority goal since the year 2000: to restore Southern California Edison to financial health in the aftermath of the California power crisis. It saw strong operating and financial performance at Edison Mission Energy which set the foundation for a plan to restore strength there. It prepared us to resume new investments at Edison Capital, placed on hold the last three years as we dedicated all our resources to rapid recovery of financial strength across Edison International. Finally, it was the year in which we were able to declare a shareholder dividend for the first time since the power crisis. We know how important this is to you.

During 2003, outstanding performance by Edison people across a wide range of company operations allowed us to meet or exceed nearly every important target we had set for the year. As a result, your stock value increased 85% during the 2003 calendar year.

SOUTHERN CALIFORNIA EDISON IN 2003

At Southern California Edison (SCE), strong operations and intense focus resulted in final recovery of $3.6 billion in previously unrecovered costs which we incurred to keep power flowing to our customers during the power crisis. Our legal right to that recovery was affirmed by both the California Supreme Court and by the U.S. federal courts.

This recovery of power crisis costs in turn paved the way for large rate reductions to our utility customers – in the aggregate, more than $1.6 billion in 2003. It also set the foundation for restoration of the credit strength essential for us to serve customers in the years to come. SCE's credit rating has now been restored to investment grade.

SCE's earnings from continuing operations of $872 million substantially exceeded both our internal targets and market expectations. Among many contributors to those earnings, two stand out: excellent operating results at our San Onofre Nuclear Generating Station (SONGS) and the resolution of a number of outstanding regulatory issues left undecided in prior years.

SCE leads U.S. utilities in the use of renewable energy. Last year, SCE set a new record: nearly 18% of all the kilowatt hours we provided our customers was supplied by renewable energy. Under mandates from California regulation, we have played a pioneering role in supporting the development of renewable power. At the same time, however, the state's "standard offer" contracts for these resources are much too costly. We will continue to focus on bringing these costs down, even while we continue to advocate the value of a diverse energy resource base – including renewables.

We received two notable awards in 2003. Our field employees were recognized for a second consecutive year with the Edison Electric Institute's annual "Emergency Response Award" – for preserving and restoring electric service in storm and wildfire conditions. And, for the third consecutive year, SCE was recognized as the most reliable utility in the western United States.

Finally, to our great disappointment, we learned recently that at least 12 employees from SCE's transmission and distribution organization falsified information used in customer satisfaction surveys. This was a serious breach of the company's highest value. It is essential to our business that everyone with whom we deal has confidence in our integrity. Any violation of that value will not be tolerated in our company.

EDISON MISSION ENERGY IN 2003 AND BEYOND

In 2003, the people of Edison Mission Energy (EME) managed exceptionally well the difficulties arising from the prior year's precipitous decline in U.S. wholesale power markets. As the year began, EME faced a daunting challenge: a total of $1.2 billion in EME-related debt was set to mature with no clear means for extending or refinancing that debt.

Because all EME financings are "non-recourse" to Edison International (EIX), our shareholders are positioned to benefit from up-side value at EME; but, beyond the equity previously invested, they are shielded from down-side risk. We require that EME meet its debt challenges exclusively on the strength of its own resources. And it is doing so.

EME people across each region operated our generation facilities at record levels in 2003, and significantly exceeded our annual earnings and cash flow targets. For the year, excluding impairment charges, EME produced earnings from continuing operations of $214 million – compared with the January 2003 outlook of no net income.

That performance made the critical difference for us. At the beginning of 2003, debt markets priced EME bonds as if that portion of our business would fail. Three other major U.S. independent power companies did fail altogether last year. With strong results

through three quarters, we were able to put forth a comprehensive plan for going forward. By year end, the maturing EME-related debt was paid off and ongoing liquidity was enhanced through new borrowings and the strength of internal cash flows.

The EME debt restructure plan will require no new investment on the part of EIX going forward. However, in order to restore financial strength to EME as rapidly as possible, we have placed all of EME's non-U.S. generation facilities up for sale. This was a difficult decision. A talented and dedicated team of EME people developed this large and valuable diversified portfolio of power plants over the past 15 years. But we believe the sale proceeds will make a decisive difference in providing the ongoing EME with reduced debt costs and improved financial health for the future. We expect to complete the sale near the end of 2004.

Following the international asset sale, EME operations in the U.S. will focus primarily on 7,500 megawatts (MW) of low-cost, coal-fired power generation in Illinois and Pennsylvania selling into wholesale markets there, and on slightly less than 1,000 MW of natural gas-fired power generation in California selling under contract to utility buyers. In total capacity, even after the currently planned power plant sales, EME's power generation will be about one and one-half times the size of SCE's power generation. With these plants, EME will concentrate on developing a diverse portfolio of contracts for sale of our power, and on continuing to generate positive margins on high volumes of energy sold.

Some of the principal power markets served by EME in the Midwest and East currently have an oversupply of generation resources. This means that "capacity values" – as reflected in customer payments for assurance that power plants will be available when needed – are now very limited or absent in those markets. Capacity values will be restored at some point as the supply/demand balance returns. Our planning does not assume that this will happen soon; but when it does, it should further improve our results.

EDISON CAPITAL

Last year's company achievements also allow us to look forward to growing our Edison Capital business again. Edison Capital had been constrained from new investments since the power crisis in order to focus the entire company's efforts on building cash and restoring credit. Edison Capital people contributed significantly to that accelerated recovery effort, including providing $225 million in dividends to the parent company last year. Beginning this year, we are refocusing on new investments initially concentrated in two areas in which Edison Capital developed expertise in the past: renewable energy and affordable housing.

WHAT LIES AHEAD FOR SCE

In 2003, SCE regained the minimum financial health necessary to assure reasonable access to capital markets essential to the utility business. But that in itself is not sufficient to optimize our ability to serve our customers and shareholders well in the years to come.

In the next several years, California's electric system will require billions of dollars of investment in power transmission and distribution systems. A large part of the transmission and distribution in the State was built 40 or more years ago. These older systems are beginning to show their age. They need to be replaced or reconstructed on a planned basis. Compounding this need for major new capital investment is the substantial growth in new customers we are experiencing at SCE.

California will also need new power generating facilities. In February and March, SCE received final state and federal regulatory agency approvals for construction of a critically needed addition to California's power generating capacity. This new natural gas-fired 1,054-MW power plant, known as Mountainview, is being built in the heart of SCE's fastest growing customer base east of Los Angeles County. Mountainview will come on line just in time to help avoid an unacceptably large risk of summer power outages in 2006.

Even as we move forward with new power generation, SCE faces challenges with respect to its existing generation facilities which today provide both low customer costs and fuel-supply diversity. The continued availability of the SCE-operated Mohave coal-fired plant is uncertain beyond the end of next year, due primarily to issues pertaining to adequate water and coal supply. Looking further into the future, the SCE-operated SONGS will need a large investment to replace its existing steam generators, if it is to be counted on to operate beyond 2009. That plant is essential to electric system reliability and operating stability in Southern California. As yet, however, there is no agreement on the part of our co-owners in that facility on whether to make that critical investment.

Now that SCE's financial health is improving, public officials may once again be tempted to impose on us new and costly obligations. Major new contractual obligations, involving commitments of millions or even billions of dollars, would again stress the company's credit strength. Where these are not strictly necessary to serve our customers, we will vigorously oppose them. Where they are appropriate, we will seek reasonable compensation for enabling others to lean on our credit.

UNRESOLVED FUNDAMENTAL ISSUES IN CALIFORNIA

Reliable electric systems require sound, long-term planning, and major capital investments made on a timely basis. Commitment of capital, in turn, requires a durable legal and regulatory framework within which that investment can take place. In the aftermath of the power crisis, there is neither a comprehensive framework nor a consensus on what such a framework should look like.

In the last two years, the California Public Utilities Commission (CPUC) has taken significant steps toward developing an orderly plan for going forward. The CPUC has concluded that investor-owned utilities

should own and operate power plants and should also contract for additional power to ensure sufficient reserves to meet customer needs. This makes sense; but critical questions remain unresolved.

The first is how new power generation will be built and financed. The CPUC correctly proposes to retain judgment to determine which plants and what mix of utility-owned and utility-contracted plants best serve customers. However, some argue that every new plant investment should be made in a statutorily prescribed auction process, the financial credit for which would be provided by long-term utility contracts. This would reduce the important role of judgment in selecting plants and would pass most market risks to utilities, with no corresponding utility benefit.

Another key issue – as yet largely unresolved – is whether utility customers will again be allowed to opt out of utility systems. That raises questions about whether investor-owned utilities will have a reasonably predictable customer base over the next decades. Utilities have traditionally invested in electric facilities and recovered reasonably incurred costs from customers through rates spread over the long lives of those assets. To the extent that there is doubt about the practical capacity of the California regulatory framework to allow utilities to plan their recovery of major commitments over as much as three decades, customer risks and costs will go up.

A high-priority task for your management team in the next year or years will be to advocate effectively to state officials the adoption of a sound, comprehensive legal and regulatory framework to ensure, at reasonable cost, California electric system reliability. Southern California Edison's future health depends on providing our customers those essential values.

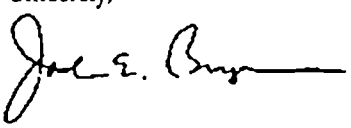
IN CONCLUSION

The accomplishments of the past year are attributable in large part to the focus, talent, experience and energies of the people who make their careers with our company. They are outstanding at what they do.

Thanks are also due to our Board of Directors. I especially want to recognize two retiring directors, Joan Hanley and Dan Tellep. They have given us many years of sound guidance and counsel.

Finally, we extend our deepest thanks to you, our shareholders. Your investment in us is what makes our business possible. We are committed to seeing to it that you will be well-served by your investment in us.

Sincerely,



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

March 24, 2004

EDISON INTERNATIONAL

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

Edison International's operating companies have principal offices in California, Boston, Chicago, Washington, D.C., Australia, Singapore, and the United Kingdom.

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INTRODUCTION

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

Edison International is engaged in the business of holding, for investment, the common stock of its subsidiaries. Edison International's principal operating subsidiaries are Southern California Edison Company (SCE), Edison Mission Energy (EME) and Edison Capital. Mission Energy Holding Company (MEHC) is a holding company for EME. SCE comprises the largest portion of the assets and revenue of Edison International. In this MD&A, except when stated to the contrary, references to each of Edison International, SCE, EME, Edison Capital or MEHC mean each such company with its subsidiaries on a consolidated basis. References to Edison International (parent) or parent company mean Edison International on a stand-alone basis, not consolidated with its subsidiaries. References to SCE, EME, Edison Capital or MEHC followed by (stand alone) mean each such company alone, not consolidated with its subsidiaries.

This MD&A is presented in 13 major sections. The MD&A begins with an Edison International management overview and a brief review of the company's consolidated earnings for 2003. Following is a company-by-company discussion of Edison International's principal operating subsidiaries (SCE, MEHC and EME, Edison Capital) and Edison International (parent). Each principal operating subsidiary's discussion includes a management overview and discussions of liquidity, market risk exposures, and other matters (as relevant to each principal operating subsidiary). The remaining sections discuss Edison International on a consolidated basis, including results of operations and historical cash flow analysis, discontinued operations, acquisitions and dispositions, critical accounting policies, new accounting principles, commitments and guarantees, off-balance sheet transactions, and other developments. These sections should be read in conjunction with each subsidiary's section.

EDISON INTERNATIONAL

EDISON INTERNATIONAL: MANAGEMENT OVERVIEW

Edison International was significantly impacted by California's energy crisis, which began in late 2000, and by world-wide developments during 2001 and 2002 that adversely affected independent power producers and merchant generators. Therefore, Edison International's primary management focus in 2003 continued to be restoring the company's financial health. In this regard, three objectives were particularly critical:

- Validating and completing SCE's recovery of power procurement costs arising from the energy crisis. In July 2003, SCE completed recovery of $3.6 billion of procurement-related obligations through the regulatory account known as the Procurement-Related Obligations Account (PROACT). By late 2003, both the California Supreme Court and the United States Court of Appeals for the Ninth Circuit (Ninth Circuit) had issued decisions upholding the 2001 CPUC settlement agreement that provided for creation of the PROACT and SCE's recovery of procurement-related costs. (See "SCE: Regulatory Matters—Generation and Power Procurement—CPUC Litigation Settlement Agreement," and "—PROACT Regulatory Asset").

- Comprehensively addressing the indebtedness at EME and its subsidiaries that mature or expire in 2003 and 2004, with a focus on debt reduction. In December 2003, EME's subsidiary, Mission Energy Holding International, Inc., received funding under a three-year, $800 million secured loan which was used, together with other internally generated cash, to repay $1.2 billion of EME and Edison Mission Midwest Holdings indebtedness. See further discussion under "MEHC and EME: Liquidity—Key Financing Developments." This was the first step in a four-part restructuring plan announced in November 2003. The remaining steps are described below.

- Positioning the company to resume common stock dividends. In November 2003, Edison International paid previously deferred interest on its quarterly income debt securities, which was a precondition to declaring a common stock dividend. In December 2003, the Board of Directors of Edison International declared a 20¢ per share common stock quarterly dividend. The $65 million dividend payment was made on January 30, 2004.

In 2004, Edison International's management intends to focus on continuing the company's financial recovery and resuming investments in growth at Edison Capital. Key objectives in 2004 include:

- Completing the remaining three steps in EME's four-part restructuring plan, which consists of refinancing indebtedness associated with EME's Illinois plants, including termination of the lease at the Collins Station, selling some or all of EME's international operations and using the proceeds of asset sales to reduce EME's consolidated indebtedness. See further discussion in "MEHC and EME: Management Overview—EME's Restructuring Plan" and "MEHC and EME: Liquidity—Key Financing Developments—EME's Subsidiary Financing Plans—Agreement in Principle to Terminate the Collins Station Lease," and "—Edison Mission Midwest Holdings."

- Reducing Edison International (parent)'s debt. At December 31, 2003, Edison International (parent) had outstanding $618 million of notes due September 2004. During January and February 2004, Edison International repurchased approximately $46 million of these notes, leaving a remaining balance of $572 million of notes due in September 2004. (See "Edison International (Parent): Liquidity Issues").

- Making important investments at SCE to ensure electric reliability. SCE currently plans to invest up to $9 billion over the next five years to replace and expand distribution and transmission infrastructure and construct and replace generation assets. (See "SCE: Management Overview").

- Restarting investments at Edison Capital in affordable housing and electric infrastructure, ending a three-year investment hiatus (see "Edison Capital: Management Overview").

Edison International's recorded earnings were $821 million or $2.52 per share in 2003, compared to $1.1 billion or $3.31 per share in 2002, which included a gain of $480 million related to a regulatory decision on SCE's utility-retained generation (URG). Excluding this one-time 2002 gain, Edison International's earnings from continuing operations in 2003 increased $124 million over 2002. Major factors contributing to the increase of $124 million over the prior year included the resolution of significant regulatory proceedings at SCE, the impact of higher United States wholesale energy prices on EME, increased generation from EME's Homer City plant and the absence of write-offs incurred in 2002 at EME. These positive impacts to earnings were partially offset in 2003 by asset impairment charges at EME. Edison International's consolidated earnings for 2003 also included a gain on an SCE asset sale and related operating earnings totaling $50 million reported in discontinued operations, and charges of $9 million for the cumulative effect of a change in accounting principles at EME. For a detailed review and analysis of the consolidated results of operations and historical cash flows, see "Results of Operations and Historical Cash Flow Analysis" section.

SOUTHERN CALIFORNIA EDISON COMPANY

SCE: MANAGEMENT OVERVIEW

Background

SCE is an investor-owned utility company providing electricity to retail customers in central, coastal and southern California. SCE is regulated by the California Public Utilities Commission (CPUC) and the Federal Energy Regulatory Commission (FERC). SCE bills its customers for the sale of electricity at rates authorized by these two commissions. These rates are categorized into two groups: base rates and cost-recovery 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 the net book value of SCE's investment in generation and distribution plant (or rate base). Base rates provide for recovery of operations and maintenance (O&M) 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 currently authorized by the CPUC through a General Rate Case (GRC) proceeding. In a GRC proceeding, SCE files an application with the CPUC to update its authorized annual revenue requirement. After a review process and hearings, the CPUC sets an annual revenue requirement by multiplying an authorized rate of return, determined in annual cost of capital proceedings (as discussed below), by rate base, then adding to this amount the adopted O&M costs and capital-related carrying costs. Adjustments to the revenue requirement for the remaining years of a typical three-year GRC cycle are requested from the CPUC based on criteria established in a GRC proceeding for escalation in O&M costs, changes in capital-related costs and the expected number of nuclear refueling outages. Variations in generation and distribution revenue arising from the difference between forecast and actual electricity sales are recorded in balancing accounts for future recovery or refund, and do not impact SCE's operating profit, while differences between forecast and actual costs, other than cost-recovery costs (see below), do impact profitability.

SCE's capital structure, including the authorized rate of return, is regulated by the CPUC and is determined in annual cost of capital proceedings. The rate of return is a blend of a return on equity and cost of long-term debt and preferred stock. SCE's 2003 cost of capital decision, issued on November 7, 2002, will remain in effect throughout 2004. Accordingly, SCE's CPUC-authorized rate of return of 9.75%, return on common equity of 11.6% and authorized rate-making capital structure will be maintained through 2004.

Current CPUC ratemaking also provides for performance incentives or penalties for differences between actual results and GRC-determined standards of reliability, customer satisfaction and employee safety.

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 when the application is filed, and revenue is subject to refund until a FERC decision is issued. SCE currently receives approximately $260 million in annual revenue to recover the costs associated with its transmission function and to earn a reasonable return on its $1.1 billion transmission rate base.

Cost-Recovery Rates: Revenue requirements to recover SCE's costs of fuel, power procurement, demand-side management programs, nuclear decommissioning costs, and rate reduction debt requirements are authorized in various CPUC proceedings on a cost-recovery basis, with no markup for return or profit. Approximately 50% 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 in these categories in future proceedings, under- or over-collections in these balancing accounts can build rapidly due to fluctuating prices (particularly in power procurement) and can greatly impact cash flows. 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.

As described below under "SCE: Regulatory Matters—Generation and Power Procurement—CDWR Power Purchases and Revenue Requirement Proceedings," the California Department of Water Resources (CDWR) began purchasing power on behalf of utility customers during the California energy crisis. In addition to billing its customers for SCE's power procurement activities, SCE also bills and collects from its customers for power purchased and sold by the CDWR, CDWR bond-related charges and direct access exit fees. These amounts are remitted to the CDWR as they are collected and are not recognized as revenue by SCE. As a result, these transactions should have no impact on SCE's earnings or cash flow.

For a discussion of important issues related to the rate-making process, see the "SCE: Regulatory Matters" section.

SCE Issues Overview

This overview discusses key business issues facing SCE. It is not intended to be an exhaustive discussion. It includes issues that could materially affect SCE's earnings, cash flow or business risk. The overview includes a discussion of current and planned capital expenditures (including the acquisition and construction of the Mountainview project, either potential expenditures or the possibility of a shutdown at the Mohave Generating Station (Mohave), and costs of replacing the steam generators at the San Onofre Nuclear Generating Station (San Onofre)), anticipated procurement requirements (including the effects of a resource adequacy requirement, community aggregation, and related ratemaking), and the 2003 and 2006 CPUC General Rate Cases.

The issues discussed in this overview are described in more detail in the remainder of this "Southern California Edison Company" section.

SCE's utility business is experiencing significant growth in actual and planned capital expenditures. SCE plans to spend up to $1.9 billion during 2004, compared to $1.2 billion in 2003. The growth in spending will require a partial reinvestment of earnings and issuance of debt securities to maintain a balanced capital structure, as required by the CPUC. For 2005 and beyond, capital spending is anticipated to remain at levels substantially above historical levels, but somewhat below planned spending for 2004.

Each of SCE's business areas (distribution, transmission and generation) is contributing to the capital spending growth. The distribution area, which represents approximately 70% of SCE's rate base, is experiencing continued expansion of the number of customer accounts. Beginning with a base of 4.6 million active accounts, for 2004, SCE expects to add approximately 60,000 new accounts, and forecasts a similar level of activity over the next several years. SCE also forecasts that it will need to accelerate the replacement of distribution poles, transformers and other infrastructure to maintain existing levels of system reliability.

SCE forecasts that expenditures for transmission facilities will substantially increase over the balance of the decade. SCE is now planning for and beginning to construct new substations to meet customer load-growth requirements. Moreover, SCE is conducting preliminary engineering on new and existing transmission lines that would expand the capacity to bring in additional energy from the Southwest.

In 2004, generation capital expenditures will increase dramatically, driven primarily by the recently approved Mountainview project. In addition, SCE will spend in excess of $50 million at the San Onofre

plant to construct facilities to protect the site against a design basis threat as determined by the Nuclear Regulatory Commission. These expenditures are in addition to ongoing capital expenditures to maintain the safety and reliability of SCE's nuclear, coal and hydroelectric facilities. Beyond 2004, SCE may replace the San Onofre steam generators in the 2009–2010 time frame. Given the lead-time requirements to fabricate the steam generators, SCE must make commitments to begin fabrication during 2004.

Recently, the CPUC ordered all load-serving entities to procure sufficient resources to meet their customers' needs. This resource adequacy requirement phases in over the 2005–2008 period and requires planning reserve margins of 15–17% of peak load. This resource adequacy requirement, combined with the anticipated closure of Mohave at the end of 2005, expected reductions in deliveries under CDWR contracts, expected expiration of contracts with some independent power producers known as qualifying facilities (QFs), and expected peak-load growth of 1.5–2.0% per year, will require SCE to either construct new generation facilities or enter into additional power-purchase contracts to provide for forecasted customer requirements. Implementation of the CPUC order will be addressed in workshops commencing in mid-March 2004.

At the same time that SCE is evaluating new generation investments and contractual obligations, SCE has raised fundamental concerns about the stability of its customer base in the CPUC's ongoing long-term procurement proceeding. The CPUC's direct access rules, the possible expansion of community choice aggregation, other forms of municipalization, and application of exit fees to departing customers all affect the ability of SCE to retain bundled service customers (customers who purchase power from SCE). It is SCE's goal to ensure that customers who depart from utility generation service pay their fair share of costs, and that costs are not unfairly shifted to remaining bundled service customers, which could have the effect of increasing SCE's rates and causing more customers to seek alternative providers.

SCE is aware that the concern for high rates was a contributing factor that led California regulators to deregulate the electric services industry in the mid-1990's. Today, SCE's system average rate is 12.3¢-per-kilowatt-hour (kWh) for bundled service customers and its average monthly bill is $79. On a cents-per-kWh basis, SCE's average rate is above the national average, but similar to the other investor-owned electric utilities in California. Therefore, SCE is focused on providing bundled service customers competitive and stable electric rates. But this focus must be balanced with the obligation to safely and reliably serve customers.

At the beginning of 2003, SCE resumed procurement of power for its bundled service customers. During 2003, much of management's attention was focused on establishing fair and reasonable rules for the procurement of power for utility customers. Additional work is needed. For 2004 and 2005, SCE forecasts that it will have a residual long position in the majority of hours. SCE's residual-net long position arises primarily because of the CPUC's allocation of CDWR contract energy. For the reasons listed above, such as customer growth and run-off of existing contracts, SCE expects to have substantially greater power procurement requirements beyond 2005. The acquisition and construction of the Mountainview project, the replacement of the San Onofre steam generators and the expansion of transmission facilities are all part of SCE's plan to meet a portion of expected customer requirements. However, even more additional resources will be needed to meet those expected requirements.

To promote and ensure recovery of both generation investments and contract costs, SCE has established a corporate priority to secure a fair and durable regulatory framework. To this end, SCE supports adoption of Assembly Bill 2006, introduced by California's Speaker of the Assembly Fabian Nunez. The bill is pending before the California State Assembly.

SCE is in the final stages of its 2003 GRC proceeding, which will set annual base rates for the years 2003–2005 years. On February 13, 2004, SCE received a proposed decision from the administrative law judge that heard the 2003 GRC. SCE is seeking a $251 million increase in its annual base rate revenue,

but the proposed decision would allow only a $15 million increase. SCE is disappointed with the proposed decision and will press for reinstatement of its requested amount by the CPUC commissioners. The CPUC commissioners can accept, reject, or modify any proposed decision.

SCE is now preparing its 2006 General Rate Case. SCE's preliminary application files in August 2004, with the application scheduled to file before year-end 2004. With the expected growth in capital spending discussed above, SCE expects that it will need further increases in its revenue requirement.

SCE: LIQUIDITY ISSUES

SCE's liquidity is primarily affected by under- or over-collections of procurement-related costs as discussed in "SCE: Management Overview—Background" and access to capital markets or external financings. In the fourth quarter of 2003, Moody's Investors Service and Standard & Poor's both raised SCE's credit ratings to investment grade.

At December 31, 2003, SCE had cash and equivalents of $95 million. SCE's long-term debt, including current maturities, at December 31, 2003, was $4.5 billion. SCE has a $700 million credit facility that expires in December 2006. SCE drew $200 million on the facility on December 19, 2003. In addition, the facility supported letters of credit in the amount of $33 million at year-end 2003. At December 31, 2003, SCE had borrowing capacity under its credit facility of $467 million. SCE's 2004 cash requirements consist of:

- $125 million of 5.875% bonds due in September 2004;
- Approximately $246 million of rate reduction notes that are due at various times in 2004, but which have a separate cost recovery mechanism approved by state legislation and CPUC decisions;
- Projected capital expenditures of $1.9 billion, including the investment in the Mountainview project and related capital expenditures (see "Acquisitions and Dispositions");
- Dividend payments to SCE's parent company;
- Fuel and procurement-related costs; and
- General operating expenses.

SCE expects to meet its continuing obligations and cash outflows for undercollections (if incurred) through cash and equivalents on hand, operating cash flows and short-term borrowings, when necessary. Projected capital expenditures are expected to be financed through cash flows and the issuance of long-term debt.

SCE's capital structure is regulated by the CPUC. SCE's CPUC-authorized common equity to total capitalization ratio level is 48%. On October 16, 2003, SCE transferred, through a dividend to Edison International, $945 million of equity that exceeded the CPUC-authorized level. This dividend was a first step to rebalance SCE's capital structure in accordance with CPUC requirements. As of December 31, 2003, SCE's common equity to total capitalization ratio, for rate-making purposes, was approximately 55%.

In January 2004, SCE issued $975 million of first and refunding mortgage bonds. The issuance included $300 million of 5% bonds due in 2014, $525 million of 6% bonds due in 2034 and $150 million of floating rate bonds due in 2006. The proceeds were used to redeem $300 million of 7.25% first and refunding mortgage bonds due March 2026, $225 million of 7.125% first and refunding mortgage bonds

due July 2025, $200 million of 6.9% first and refunding mortgage bonds due October 2018, and $100 million of junior subordinated deferrable interest debentures due June 2044. In March 2004, SCE remarketed approximately $550 million of pollution-control bonds with varying maturity dates ranging from 2008 to 2040.

SCE resumed procurement of its residual-net short (the amount of energy needed to serve SCE's customers from sources other than its own generating plants, power-purchase contracts and CDWR contracts) on January 1, 2003, and as of December 31, 2003, had posted approximately $66 million ($33 million in cash and $33 million in letters of credit) as collateral to secure its obligations under power-purchase contracts and to transact through the Independent System Operator (ISO) for imbalance energy. SCE's collateral requirements can vary depending upon the level of unsecured credit extended by counterparties, the ISO's credit requirements, changes in market prices relative to contractual commitments, and other factors.

SCE's liquidity may be affected by, among other things, matters described in "SCE: Regulatory Matters—Generation and Power Procurement—CPUC Litigation Settlement Agreement," "—CDWR Power Purchases and Revenue Requirement Proceedings," and "—Generation Procurement Proceedings" sections.

SCE: MARKET RISK EXPOSURES

SCE's primary market risks include fluctuations in interest rates, generating fuel commodity prices and volume and counterparty credit. Fluctuations in interest rates can affect earnings and cash flows. However, fluctuations in fuel prices and volumes and counterparty credit losses temporarily affect cash flows, but should not affect earnings.

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 and to fund business operations, as well as to finance capital expenditures. The nature and amount of SCE's long-term and short-term debt can be expected to vary as a result of future business requirements, market conditions and other factors. In addition, SCE's authorized return on common equity (11.6% for 2003 and 2004), 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, 2003, SCE did not believe that its short-term debt and current portion of long-term debt and preferred stock was subject to interest rate risk, due to the fair market value being approximately equal to the carrying value.

At December 31, 2003, the fair market value of SCE's long-term debt was $4.4 billion. A 10% increase in market interest rates would have resulted in a $166 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 $183 million increase in the fair market value of SCE's long-term debt. At December 31, 2003, the fair market value of SCE's preferred stock subject to mandatory redemption was $139 million. A 10% increase in market interest rates would have resulted in a $12 million decrease in the fair market value of SCE's preferred stock subject to mandatory redemption. A 10% decrease in market interest rates would have resulted in a $14 million increase in the fair market value of SCE's preferred stock subject to mandatory redemption.

Generating Fuel Commodity Price Risk

SCE's purchased-power expense in 2003 was approximately 38% of SCE's total operating expenses. SCE recovers its reasonable power procurement costs through regulatory mechanisms established by the

CPUC. The California public utilities code provides that the CPUC shall adjust rates, or order refunds, to amortize undercollections or overcollections of power procurement costs. Until January 1, 2006, the CPUC must adjust rates if the undercollection or overcollection exceeds 5% of SCE's prior year's procurement costs, excluding revenue collected for the CDWR. As a result of these regulatory mechanisms, changes in energy prices may impact SCE's cash flows but should have no impact on earnings.

On January 1, 2003, SCE resumed procurement of its residual-net short. SCE forecasts that it will have a residual long position in the majority of hours for 2004. SCE's residual-net long position arises from an expected increase in deliveries under CDWR contracts allocated to SCE's customers. SCE has incorporated a price and volume forecast from expected sales of residual-net long power in its 2004 procurement plan filed with the CPUC, as well as in the revenue forecast used for setting rates. If actual prices or volumes vary from forecast, SCE's cash flow would be temporarily impacted, but should not affect earnings. For 2004 and beyond, several factors could cause SCE's residual-net short to be much larger than expected, including the return of direct access customers (customers who choose to purchase power directly from an electric service provider other than SCE) to utility service, lower utility generation due to expected or unexpected outages or plant closures, lower deliveries under third-party power contracts, higher than anticipated demand for electricity, or displacement of existing generation resources with economic short-term transactions. Such an increase in procurement requirements could lead to temporary revenue undercollections if the costs to purchase the additional energy were to exceed the amount recovered in rates.

SCE anticipates it will need to purchase additional capacity and/or ancillary services to meet its peak-energy requirements in 2004 and 2005. In 2006, SCE's residual-net short exposure will increase significantly from the reduction in expected CDWR power deliveries, expiration of certain contracts with QFs, expected shutdown of Mohave, and load growth.

Pursuant to CPUC decisions, SCE, as the CDWR's limited agent, arranges for natural gas and performs related services for CDWR contracts allocated to SCE by the CPUC. Financial and legal responsibility for the allocated contracts remains with the CDWR. The CDWR, through the coordination of SCE, has hedged a portion of its expected natural gas requirements for certain contracts allocated to SCE. To the extent the price of natural gas were to increase above the levels assumed for cost recovery purposes, 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 purchases power from QFs under CPUC state-mandated contracts. Contract energy prices for most nonrenewable QFs are tied to the Southern California border price of natural gas established on a monthly basis. The CPUC has authorized SCE to hedge a majority of its natural gas price exposure associated with these QF contracts. During 2003, SCE substantially hedged the risk of increasing natural gas prices through hedging instruments purchased in late 2001 pursuant to authority granted by the CPUC. The cost of these hedging instruments was recovered through PROACT. None of these hedging instruments were outstanding as of December 31, 2003. The CPUC approved SCE's short-term resource plan, which includes hedging of natural gas price exposure for its existing QF contracts for 2004. These hedging costs are recovered through a balancing account known as Energy Resource Recovery Account (ERRA) and should have no impact on earnings. SCE cannot predict with certainty whether in the future it will be able to hedge customer risk for other commodities on favorable terms or that the cost of such hedges will be fully recovered in rates.

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. 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 should not affect earnings.

SCE: REGULATORY MATTERS

This section of the MD&A describes SCE's regulatory matters in three main subsections:

- generation and power procurement;
- transmission and distribution; and
- other regulatory matters.

Generation and Power Procurement

CPUC Litigation Settlement Agreement

During the California energy crisis, prices charged by sellers of wholesale power escalated far beyond what SCE was permitted by the CPUC to charge its customers. In November 2000, SCE filed a lawsuit against the CPUC in federal district court seeking a ruling that SCE is entitled to full recovery of its electricity procurement costs incurred during the energy crisis in accordance with the tariffs filed with the FERC. In October 2001, SCE and the CPUC entered into a settlement of SCE's lawsuit against the CPUC. A key element of the 2001 CPUC settlement agreement was the establishment of a $3.6 billion regulatory balancing account, called the PROACT, as of August 31, 2001. The Utility Reform Network (TURN) and other parties appealed to the Ninth Circuit seeking to overturn the stipulated judgment of the federal district court that approved the 2001 CPUC settlement agreement. On September 23, 2002, the Ninth Circuit issued its opinion affirming the federal district court on all claims, with the exception of the challenges founded upon California state law, which the Ninth Circuit referred to the California Supreme Court.

On August 21, 2003, the California Supreme Court issued its decision on the certified questions on challenges founded upon California state law, concluding that the 2001 CPUC settlement agreement did not violate California law in any of the respects raised by the Ninth Circuit. Specifically, the California Supreme Court concluded that: (1) the commissioners of the CPUC had the authority to propose the stipulated judgment under the provisions of California's restructuring statute, Assembly Bill 1890, as amended or impacted by subsequent legislation; (2) the procedures employed by the CPUC in entering the stipulated judgment did not violate California's open meeting law for public agencies; and (3) the stipulated judgment did not violate California's public utilities code by allegedly altering rates without a public hearing and issuance of findings.

On October 22, 2003, the California Supreme Court denied TURN's petition for rehearing of the decision. The matter was returned to the Ninth Circuit for final disposition, subject to any efforts by TURN to pursue further federal appeals. On December 19, 2003, the Ninth Circuit unanimously affirmed the original stipulated judgment of the federal district court, and no petition for rehearing was filed. On January 12, 2004, the Ninth Circuit issued its mandate, relinquishing jurisdiction of the case and returning jurisdiction to the federal district court. TURN and those parties whose appeals to the Ninth Circuit were consolidated with TURN's appeal currently have 90 days from December 19, 2003 in which to seek discretionary review from the United States Supreme Court. SCE continues to believe it is probable that recovery of its past procurement costs through regulatory mechanisms, including the PROACT, will not

be invalidated. However, SCE cannot predict with certainty the ultimate outcome of further legal proceedings, if any.

PROACT Regulatory Asset

In accordance with the 2001 CPUC settlement agreement described above and an implementing resolution adopted by the CPUC, in the fourth quarter of 2001, SCE established the PROACT regulatory balancing account, with an initial balance of approximately $3.6 billion. The initial balance reflected the net amount of past procurement-related liabilities to be recovered by SCE. On a monthly basis, the difference between SCE's revenue from retail electric rates (including surcharges) and the costs that SCE was authorized by the CPUC to recover in retail electric rates was applied to the PROACT until SCE fully recovered the balance.

At July 31, 2003, the PROACT regulatory balancing account was overcollected by $148 million. On October 14, 2003, the CPUC approved SCE's advice filing which allowed SCE to transfer this July 31, 2003 overcollected PROACT balance and a temporary surcharge balancing account overcollection (see "—Generation and Power Procurement—Temporary Surcharges") to the ERRA (discussed below) on August 1, 2003, and to implement a $1.2 billion customer rate reduction effective August 1, 2003.

Energy Resource Recovery Account Proceedings

In an October 24, 2002 decision, the CPUC established the ERRA as the rate-making mechanism to track and recover SCE's: (1) fuel costs related to its generating stations; (2) purchased-power costs related to cogeneration and renewable contracts; (3) purchased-power costs related to existing interutility and bilateral contracts that were entered into before January 17, 2001; and (4) new procurement-related costs incurred on or after January 1, 2003 (the date on which the CPUC transferred back to SCE the responsibility for procuring energy resources for its customers). As described in "SCE: Management Overview," SCE recovers these costs on a cost-recovery basis, with no markup for return or profit. SCE files annual forecasts of the above-described costs that it expects to incur during the following year. As these costs are subsequently incurred, they will be tracked and recovered through the ERRA, but are subject to a reasonableness review in a separate annual ERRA application. If the ERRA overcollection or undercollection exceeds 5% of SCE's prior year's procurement costs, SCE can request an emergency rate adjustment in addition to the annual forecast and reasonableness ERRA applications.

SCE submitted its first ERRA forecast application in April 2003, in which it forecast procurement-related costs for the 2003 calendar year of $2.5 billion. On January 22, 2004, the CPUC issued a decision that approved SCE's forecast as submitted. The CPUC issued a proposed decision on February 24, 2004, approving SCE's 2004 forecast revenue requirement and rates for both generation and delivery services.

In October 2003, SCE submitted its first ERRA reasonableness review application, in which it requested the CPUC find its procurement-related operations during the period from September 1, 2001 through June 30, 2003 to be reasonable. Because this is the first annual review of this activity, pursuant to new California state law, the CPUC's interpretation and application of California state law is uncertain. SCE cannot predict with certainty the outcome of its application and recovery of its procurement-related operations costs.

Pursuant to the assigned commissioner's scoping memo issued on December 9, 2003, the CPUC's Office of Ratepayer Advocates (ORA) was allowed to review the accounting calculations used in the PROACT mechanism. The ORA testimony, due on March 19, 2004, will include an audit of these accounting calculations. Hearings are scheduled to be held during April 2004.

Utility-Retained Generation

As a result of an April 2002 CPUC decision, SCE's retained generation assets were returned to cost-of-service ratemaking after operating in a deregulated environment since 1998. The CPUC decision provided for the: (1) recovery of costs for all URG components other than San Onofre Units 2 and 3, subject to reasonableness review by the CPUC; (2) retention of the incremental cost incentive pricing mechanism (ICIP) for San Onofre Units 2 and 3 through 2003; (3) establishment of an amortization schedule for SCE's nuclear facilities that reflects their current remaining Nuclear Regulatory Commission license durations, using unamortized balances as of January 1, 2001 as a starting point; (4) establishment of balancing accounts for the costs of utility generation, purchased power, and ancillary services purchased from the ISO; and (5) continuation of the use of SCE's last CPUC-authorized return on common equity of 11.6% for SCE's URG rate base other than San Onofre Units 2 and 3, and the 7.35% return on rate base for San Onofre Units 2 and 3 under the ICIP. SCE will operate under the April 2002 CPUC decision until implementation of the 2003 GRC (see "—Transmission and Distribution—2003 General Rate Case Proceeding").

CDWR Power Purchases and Revenue Requirement Proceedings

In accordance with an emergency order by the Governor of California, the CDWR began making emergency power purchases for SCE's customers on January 17, 2001. In February 2001, a California law was enacted which authorized the CDWR to: (1) enter into contracts to purchase electric power and sell power at cost directly to SCE's retail customers; and (2) issue bonds to finance those electricity purchases. During the fourth quarter of 2002, the CDWR issued $11 billion in bonds to finance its electricity purchases. The CDWR's total statewide power charge and bond charge revenue requirements are allocated by the CPUC among the customers of SCE, Pacific Gas and Electric (PG&E) and San Diego Gas & Electric (SDG&E). Amounts billed to and collected from SCE's customers for electric power purchased and sold by the CDWR (approximately $1.7 billion in 2003) are remitted directly to the CDWR and are not recognized as revenue by SCE.

Direct Access Proceedings

From 1998 through mid-September 2001, SCE's customers were able to choose to purchase power directly from an electric service provider other than SCE (thus becoming direct access customers) or continue to purchase power from SCE. During that time, direct access customers received a credit for the generation costs SCE saved by not serving them, resulting in additional undercollected power procurement costs to SCE during 2000 and 2001. On March 21, 2002, the CPUC issued a decision affirming that new direct access arrangements entered into by SCE's customers after September 20, 2001 are invalid. That decision did not affect direct access arrangements in place before that date.

In May 2003, a CPUC decision allowed customers with valid direct access arrangements to switch back and forth between bundled service provided by SCE and direct access. This decision, as well as CPUC decisions or proceedings discussed below, affects SCE's ability to predict the size of its customer base, the amount of bundled service load for which it must procure or generate electricity, its net-short position and its ability to plan for resource requirements.

The CPUC has received several petitions requesting clarification of previous decisions on whether to allow load growth on existing direct access accounts or add new accounts if necessary to accommodate direct access customers who relocate their facilities. Recently, the CPUC agreed, in response to one of these petitions, to allow direct access customers to add new accounts when relocating facilities as long as there is no increase in a customer's total eligible direct access load. SCE cannot predict how the CPUC will rule on the remaining petitions. If the CPUC allows load growth on existing direct access accounts and allows new direct access accounts to be added notwithstanding the suspension of direct access, the

level of direct access load in SCE's territory could rise considerably, resulting in a shift of a greater portion of SCE's costs to bundled service customers.

The CPUC has also opened a proceeding to identify issues relating to the implementation of a 2002 California law authorizing community choice aggregation. This form of direct access allows local governments to combine the loads of its residents, businesses, and municipal facilities in a community-wide electricity buyers program and to create an entity called a community choice aggregator. Hearings on this matter are scheduled to begin in May 2004. Depending on how many, if any, cities choose to participate in community choice aggregation, a large amount of load could depart from SCE's bundled service, resulting in additional shifting of cost responsibility.

The CPUC has issued decisions or has opened proceedings to establish various charges (exit fees) for customers who (1) switch to another electric service provider, (2) switch to a municipal utility; or (3) install onsite generation facilities or arrange to purchase power from another entity that installs such facilities. The charges recovered from these customers are used to reduce SCE's rates to bundled service customers and have no impact on earnings.

Temporary Surcharges

A March 2001 CPUC decision, authorized a 3¢-per-kWh revenue surcharge to SCE's customers and made permanent a 1¢-per-kWh surcharge to SCE's customers authorized in January 2001. In addition, the CPUC authorized an additional 0.6¢-per-kWh catch-up surcharge for a twelve-month period, beginning in June 2001, to compensate SCE for a delay in collecting the 3¢-per-kWh surcharge. These surcharges were used for SCE's procurement costs.

The CPUC later allowed the continuation of the 0.6¢-per-kWh catch-up surcharge. Amounts collected between June 2002 and December 2002 were to be used to recover 2003 procurement costs. As a result, at December 31, 2002, this revenue ($187 million of surcharge revenue) was credited to a regulatory liability account until it was used to offset SCE's higher 2003 procurement revenue requirement. Between January 1, 2003 and July 31, 2003, $150 million of this regulatory liability account was amortized into revenue. The remaining balance of $37 million was transferred to the ERRA as of August 1, 2003.

The $1.2 billion customer rate reduction plan implemented by SCE eliminated all of the temporary surcharges (see "—Generation and Power Procurement—PROACT Regulatory Asset").

Generation Procurement Proceedings

SCE resumed power procurement responsibilities for its residual-net short position on January 1, 2003, pursuant to CPUC orders and California statutes passed in 2002. The current regulatory and statutory framework requires SCE to assume limited responsibilities for CDWR contracts allocated by the CPUC, and provide full power procurement responsibilities on the basis of annual short-term procurement plans, long-term resource plans and increased procurement of renewable resources.

Short-Term Procurement Plan

In 2003, SCE operated under a CPUC-approved short-term procurement plan, which includes contracts entered into during a transitional period beginning in August 2002 for deliveries in 2003 and the allocation of CDWR contracts. In December 2003, the CPUC adopted a 2004 procurement plan for SCE, which established a target level for spot market purchases equal to 5% of monthly need, and allowed SCE to enter into contracts of up to five years.

Long-Term Resource Plan

On April 15, 2003, SCE filed its long-term resource plan with the CPUC, which includes a 20-year forecast. SCE's long-term resource plan included both a preferred plan and an interim plan (both described below). On January 22, 2004, the CPUC issued a decision which did not adopt any long-term resource plan, but adopted a framework for resource planning. Until the CPUC approves a long-term resource plan for SCE, SCE will operate under its interim resource plan.

- Preferred Resource Plan: The preferred resource plan contains long-term commitments intended to encourage investment in new generation and transmission infrastructure, increase long-term reliability and decrease price volatility. These commitments include energy efficiency and demand-response investments, additional renewable resource contracts that will meet or exceed the requirements of legislation passed in 2002, additional utility and third-party owned generation, and new major transmission projects.

- Interim Resource Plan: The interim resource plan, by contrast, relies exclusively on new short- and medium-term contracts with no long-term resource commitments (except for new renewable contracts).

In its long-term resource plan filing, SCE maintained that implementation of its preferred resource plan requires resolution of various issues including: (1) stabilizing SCE's customer base; (2) restoring SCE's investment-grade creditworthiness; (3) restructuring regulations regarding energy efficiency and demand-response programs; (4) removing barriers to transmission development; (5) modifying prior decisions, which impede long-term procurement; and (6) adopting a commercially realistic cost-recovery framework that will enable utilities to obtain financing and enable contracting for new generation.

Under the framework adopted in the CPUC's January 22, 2004 decision, all load-serving entities in California have an obligation to procure sufficient resources to meet their customers' needs. This resource adequacy requirement phases in over the 2005–2008 period and requires planning reserve margins of 15–17% of peak load. The decision requires SCE to enter into forward contracts for 90% of SCE's summer peaking needs a year in advance and to file a revised long-term resource plan in 2004. The decision does not comprehensively address important issues SCE has raised about its customer base, recovery of indirect procurement costs (including debt equivalence) and other matters.

Procurement of Renewable Resources

As part of SCE's resumption of power procurement, in accordance with a California statute passed in 2002, SCE is required to increase its procurement of renewable resources by at least 1% of its annual electricity sales per year so that 20% of its annual electricity sales are procured from renewable resources by no later than December 31, 2017. In June 2003, the CPUC issued a decision adopting preliminary rules and guidance on renewable procurement-related issues, including penalties for noncompliance with renewable procurement targets. As of December 31, 2003, SCE procured approximately 18% of its annual electricity from renewable resources.

SCE has received bids for renewable resource contracts in response to a solicitation it made in August 2003, and is proceeding to enter into negotiations for contracts with some bidders based upon its preliminary bid evaluation.

CDWR Contract Allocation and Operating Order

The CDWR power-purchase contracts entered into as a result of the California energy crisis have been allocated on a contract-by-contract basis among SCE, PG&E and SDG&E, in accordance with a 2002

CPUC decision. SCE only assumes scheduling and dispatch responsibilities and acts only as a limited agent for the CDWR for contract implementation. Legal title, financial reporting and responsibility for the payment of contract-related bills remain with the CDWR. The allocation of CDWR contracts to SCE significantly reduces SCE's residual-net short and also increases the likelihood that SCE will have excess power during certain periods. SCE has incorporated CDWR contracts allocated to it in its procurement plans. Wholesale revenue from the sale of excess power, if any, is prorated between the CDWR and SCE.

SCE's maximum annual disallowance risk exposure for contract administration, including administration of allocated CDWR contracts and least cost dispatch of CDWR contract resources, is $37 million. In addition, gas procurement, including hedging transactions, associated with CDWR contracts is included within the cap.

Mohave Generating Station and Related Proceedings

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

Due to the lack of progress in negotiations with the Tribes and other parties to resolve several coal and water supply issues, SCE's application stated that SCE would probably be unable to extend Mohave's operation beyond 2005. The uncertainty over a 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 pollution-control equipment that must be put in place in order for Mohave to continue to operate beyond 2005, pursuant to a 1999 consent decree concerning air quality.

Negotiations are continuing among the relevant parties in an effort to resolve the coal and water supply issues, but no resolution has been reached. The Mohave co-owners, the Tribes, and the federal government have recently finalized a memorandum of understanding under which the Mohave co-owners will fund, subject to the terms and conditions of the memorandum of understanding, a $6 million study of a possible alternative groundwater source for the slurry water. The study is expected to begin in early 2004. SCE and other parties submitted further testimony and made various other filings in 2003 in SCE's application proceeding. On February 9, 2004, the CPUC held a prehearing conference to discuss whether additional testimony and hearings are needed to determine the future of the plant. The CPUC has not issued any ruling as result of the prehearing conference, but has indicated that further testimony can be expected in early to mid-2004. The outcome of the coal and water negotiations and SCE's application are not expected to impact Mohave's operation through 2005, but could have a major impact on SCE's long-term resource plan.

For additional matters related to Mohave, see "SCE: Other Developments—Navajo Nation Litigation."

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

Transmission and Distribution

2003 General Rate Case Proceeding

On May 3, 2002, SCE filed its application for a 2003 GRC, requesting: (1) a 2003 revenue requirement of approximately $3.1 billion; (2) a 2004 revenue requirement of approximately $3.5 billion; and (3) a 2005 revenue requirement of approximately $3.7 billion. These revenue requirements were based on SCE's projected rate base amounts of $7.8 billion in 2003, $8.2 billion in 2004 and $8.5 billion in 2005. When compared to forecast revenue at currently authorized rates (approximately $2.8 billion), SCE's 2003 GRC request was an increase of $286 million, which was subsequently revised to an increase of $251 million. The requested revenue increase for 2003 was primarily related to capital additions, updated depreciation costs and projected increases in pension and benefit expenses. The application also proposed an estimated base rate revenue decrease of $78 million in 2004, and a subsequent increase of $116 million in 2005. The forecast reduction in 2004 was largely attributable to the expiration of the San Onofre ICIP rate-making mechanism at year-end 2003 and a forecast of increased sales. The expiration of San Onofre ICIP mechanism is expected to decrease SCE's 2004 earnings by approximately $100 million. Beginning in 2004, San Onofre Units 2 and 3 cost recovery reverts to cost-of-service ratemaking.

In a proposed decision issued on February 13, 2004, a CPUC administrative law judge recommended that the CPUC adopt only $15 million of the $251 million increase in authorized base rate revenue requirement that SCE had requested. SCE filed comments opposing parts of the proposed decision in an attempt to restore important components of the requested revenue requirement. The CPUC is scheduled to vote on the proposed decision on March 16, 2004, either modifying or accepting it. If an alternate decision is proposed, a final decision could be delayed into April 2004. If the CPUC adopts the administrative law judge's proposed decision without modification, and if SCE does not reduce its expected capital or operating expenditures accordingly, SCE estimates that on an annual basis SCE's earnings per share would be about 15¢-per-share lower and cash flow would be approximately $135 million lower than if SCE's base rate request had been granted in full. SCE cannot predict with certainty the final outcome of SCE's GRC application.

Because processing of the GRC took longer than initially scheduled, in May 2003 the CPUC approved SCE's request to establish a memorandum account to track the revenue requirement increase during the period between May 22, 2003 (the date a final CPUC decision was originally scheduled to be issued) and the date a final decision is ultimately adopted. The revenue requirement approved in the final GRC decision will be effective retroactive to May 22, 2003. Any balance in the GRC memorandum account authorized by the CPUC would be recovered in rates beginning in 2004, together with the combined revenue requirement authorized by the CPUC in the GRC decision for 2003 and 2004.

Hearings to address revenue allocation and rate design issues have been continued until after the CPUC issues a decision on SCE's revenue requirement. Due to the implementation of SCE's $1.2 billion customer rate-reduction plan, rate design changes will not be effective until August 2004, at the earliest. Until SCE's 2003 GRC is implemented, SCE's revenue requirement related to distribution operations is determined through a performance-based rate-making (PBR) mechanism.

Electric Line Maintenance Practices Proceeding

In August 2001, the CPUC issued an order instituting investigation regarding SCE's overhead and underground electric line maintenance practices. The order was based on a report issued by the CPUC's Consumer Protection and Safety Division, which alleged a pattern of noncompliance with the CPUC's general orders for the maintenance of electric lines for 1998–2000. The order also alleged that noncompliant conditions were involved in 37 accidents resulting in death, serious injury or property

damage. The Consumer Protection and Safety Division identified 4,817 alleged violations of the general orders during the three-year period; and the order put SCE on notice that it could be subject to a penalty of between $500 and $20,000 for each violation or accident. In its opening brief on October 21, 2002, the Consumer Protection and Safety Division recommended that SCE be assessed a penalty of $97 million.

On June 19, 2003, a CPUC administrative law judge issued a presiding officer's decision on the Consumer Protection and Safety Division report. The decision did the following:

- Fined SCE $576,000 for 2% of the alleged violations involving death, injury or property damage, failure to identify unsafe conditions or exceeding required inspection intervals. The decision did not find that any of the alleged violations compromised the integrity or safety of SCE's electric system or were excessive compared to other utilities.

- Ordered SCE to consult with the Consumer Protection and Safety Division and refine SCE's maintenance priority system consistent with the decision.

- Adopted an interpretation that all SCE's nonconformances with the CPUC's general orders for the maintenance of electric lines are violations subject to potential penalty.

On July 21, 2003, SCE filed an appeal with the CPUC challenging, among other things, the decision's interpretation of nonconformance. The Consumer Protection and Safety Division also appealed, challenging the fact that the decision did not penalize SCE for 4,721 of the 4,817 alleged violations. A final decision is scheduled to be issued on March 16, 2004.

Transmission Rate Case

In July 2000, the FERC issued a decision in SCE's 1998 transmission rate case in which it ordered a reduction of approximately $38 million to SCE's requested annual transmission revenue requirement of $213 million. In the decision, the FERC rejected SCE's proposed method for allocating overhead costs between transmission and distribution operations, which accounted for approximately $24 million of the $38 million reduction. After the FERC decision, SCE sought recovery in distribution rates from the CPUC. In third quarter 2003, the CPUC authorized recovery of $133 million of overhead costs for the period April 1, 1998 to August 31, 2002, and SCE credited this amount to provisions for regulatory adjustment clauses – net in the consolidated statements of income. On September 22, 2003, the ORA applied for rehearing of the matter. On February 11, 2004, the CPUC denied the ORA's request and reaffirmed its decision authorizing recovery.

Wholesale Electricity and Natural Gas Markets

In 2000, the FERC initiated an investigation into the justness and reasonableness of rates charged by sellers of electricity in the California Power Exchange (PX)/ ISO markets. On March 26, 2003, the FERC staff issued a report concluding that there had been pervasive gaming and market manipulation of both the electric and natural gas markets in California and on the West Coast during 2000-2001 and describing many of the techniques and effects of that market manipulation. 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. Under the 2001 CPUC settlement agreement, mentioned in "—Generation and Power Procurement—CPUC Litigation Settlement Agreement," 90% of any refunds actually realized by SCE will be refunded to customers, except for the El Paso Natural Gas Company settlement agreement discussed below.

El Paso Natural Gas Company entered into a settlement agreement with parties to a class action lawsuit (including SCE, PG&E and the State of California) settling claims stated in proceedings at the FERC and

in San Diego County Superior Court that El Paso Natural Gas Company had manipulated interstate capacity and engaged in other anticompetitive behavior in the natural gas markets in order to unlawfully raise gas prices at the California border in 2000–2001. The San Diego County Superior Court approved the settlement on December 5, 2003. Notice of appeal of that judgment was filed by a party to the action on February 6, 2004. Accordingly, until the appeal is resolved, the judgment is not final and no refunds will be paid. Pursuant to a CPUC decision, SCE will refund to customers any amounts received under the terms of the El Paso Natural Gas Company settlement (net of legal and consulting costs) through its ERRA mechanism. In addition, amounts El Paso Natural Gas Company refunds to the CDWR will result in equivalent reductions in the CDWR's revenue requirement allocated to SCE.

On February 24, 2004, SCE and PG&E entered into a settlement agreement with The Williams Cos. and Williams Power Company, providing for approximately $140 million in refunds against some of Williams' power charges in 2000–2001. The allocation of refunds under the settlement agreement has not been determined. The settlement is subject to the approval of the FERC, the CPUC and the PG&E bankruptcy court.

Other Regulatory Matters

Catastrophic Event Memorandum Account

The catastrophic event memorandum account (CEMA) is a CPUC-authorized mechanism that allows SCE to immediately start the tracking of all of its incremental costs associated with declared disasters or emergencies and to subsequently receive rate recovery of its reasonably incurred costs upon CPUC approval. Incremental costs associated with restoring utility service; repairing, replacing or restoring damaged utility facilities; and complying with governmental agency orders are tracked in the CEMA. SCE currently has a CEMA for the bark beetle emergency and initiated a second CEMA associated with the fires that occurred in SCE territory in October 2003. Costs tracked through the CEMA mechanism are expected to be recovered in future rates with no impact on earnings. However, cash flow will be impacted due to the timing difference between expenditures and rate recovery.

Bark Beetle CEMA

On March 7, 2003, the Governor of California issued a proclamation declaring a state of emergency in Riverside, San Bernardino and San Diego counties where an infestation of bark beetles has created the potential for catastrophic forest fires. The proclamation requested that the CPUC direct utilities with transmission lines in these three counties to ensure that all dead, dying and diseased trees and vegetation are completely cleared from their utility rights-of-way to mitigate the potential fire damage. SCE estimates that it may incur several hundred million dollars in incremental expenses over the next several years to remove over 350,000 of these trees. This cost estimate is subject to significant change, depending on a number of evolving circumstances, including, but not limited to the spread of the bark beetle infestation, the speed at which trees can be removed, and tree disposal costs. In 2003, SCE removed approximately 26,000 dead or dying trees at an incremental expense of approximately $18 million which has been reflected in the CEMA as of December 31, 2003. SCE expects to submit an advice filing with the CPUC in the first quarter of 2004 to recover these costs. SCE estimates that it will spend up to $150 million on this project in 2004.

Fire-Related CEMA

During the last two weeks of October 2003, wildfires damaged SCE's electrical infrastructure, primarily in the San Bernardino Mountains of Southern California where an estimated 1,500 power poles and 220 transformers were damaged or downed. SCE notified the CPUC that it initiated a CEMA on October 21, 2003 to track the incremental costs to repair and restore its infrastructure. These costs are

estimated to be approximately $30 million. The balance in this CEMA account is approximately $9 million as of December 31, 2003.

Holding Company Proceeding

In April 2001, the CPUC issued an order instituting investigation that reopened the past CPUC decisions authorizing utilities to form holding companies and initiated an investigation into, among other things: (1) whether the holding companies violated CPUC requirements to give first priority to the capital needs of their respective utility subsidiaries; (2) any additional suspected violations of laws or CPUC rules and decisions; and (3) whether additional rules, conditions, or other changes to the holding company decisions are necessary.

On January 9, 2002, the CPUC issued an interim decision interpreting the CPUC requirement that the holding companies give first priority to the capital needs of their respective utility subsidiaries. The decision stated that, at least under certain circumstances, holding companies are required to infuse all types of capital into their respective utility subsidiaries when necessary to fulfill the utility's obligation to serve its customers. The decision did not determine whether any of the utility holding companies had violated this requirement, reserving such a determination for a later phase of the proceedings. On February 11, 2002, SCE and Edison International filed an application before the CPUC for rehearing of the decision. On July 17, 2002, the CPUC affirmed its earlier decision on the first priority requirement and also denied Edison International's request for a rehearing of the CPUC's determination that it had jurisdiction over Edison International in this proceeding. On August 21, 2002, Edison International and SCE jointly filed a petition in California state court requesting a review of the CPUC's decisions with regard to first priority requirements, and Edison International filed a petition for a review of the CPUC decision asserting jurisdiction over holding companies. PG&E and SDG&E and their respective holding companies filed similar challenges, and all cases have been transferred to the First District Court of Appeals in San Francisco. On November 26, 2003, the Court of Appeals issued an order indicating it would hear the cases but did not decide the merits of the petitions. Oral argument was held before the Court of Appeals on March 5, 2004, and the Court of Appeals is expected to rule within 90 days.

Investigation Regarding Performance Incentives Rewards

SCE is eligible under its CPUC-approved PBR mechanism to earn rewards or penalties based on its performance in comparison to CPUC-approved standards of reliability, customer satisfaction, and employee safety. SCE received two letters over the last year from 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 to SCE under the PBR provisions for customer satisfaction. SCE is conducting an internal investigation and has determined that some wrongdoing by a number of the service planning employees has occurred. SCE has informed the CPUC of its findings to date, and will continue to inform the CPUC of developments as the investigation progresses. SCE anticipates that, after the investigation is completed, there may be CPUC proceedings to determine whether any portion of past and potential rewards for customer satisfaction should be refunded or disallowed. It also is possible that penalties could be imposed. SCE recorded aggregate customer satisfaction rewards of $28 million for the years 1998, 1999, and 2000. Potential customer satisfaction rewards aggregating $10 million for 2001 and 2002 are pending before the CPUC and have not been recognized in income by SCE. SCE also had anticipated that it could be eligible for customer satisfaction rewards of about $10 million for 2003. SCE has not yet been able to determine whether or to what extent employee misconduct has compromised the surveys that are the basis for a portion of the awards. Accordingly, SCE cannot predict with certainty the outcome of this matter. SCE plans to complete its

investigation as quickly as possible and cooperate fully with the CPUC in taking appropriate remedial action.

SCE: OTHER DEVELOPMENTS

Electric and Magnetic Fields

Electric and magnetic fields naturally result from the generation, transmission, distribution and use of electricity. Since the 1970s, concerns have been raised about the potential health effects of electric and magnetic fields. After 30 years of research, a health hazard has not been established to exist. Potentially important public health questions remain about whether there is a link between electric and magnetic fields exposures in homes or work and some diseases, and because of these questions, some health authorities have identified electric and magnetic fields exposures as a possible human carcinogen.

In October 2002, the California Department of Health Services released to the CPUC and the public its report evaluating the possible risks from electric and magnetic fields. The conclusions in the report of the California Department of Health Services contrast with other recent reports by authoritative health agencies in that the California Department of Health Services has assigned a substantially higher probability to the possibility that there is a causal connection between electric and magnetic fields exposures and a number of diseases and conditions, including childhood leukemia, adult leukemia, amyotrophic lateral sclerosis, and miscarriages.

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

Navajo Nation Litigation

In June 1999, the Navajo Nation filed a complaint in the United States District Court for the District of Columbia (D.C. District Court) against Peabody Holding Company (Peabody) and certain of its affiliates, Salt River Project Agricultural Improvement and Power District, and SCE arising out of the coal supply agreement for Mohave. The complaint asserts claims for, among other things, violations of the federal Racketeer Influenced and Corrupt Organizations statute, interference with fiduciary duties and contractual relations, fraudulent misrepresentation by nondisclosure, and various contract-related claims. The complaint claims that the defendants' actions prevented the Navajo Nation from obtaining the full value in royalty rates for the coal. The complaint seeks damages of not less than $600 million, trebling of that amount, and punitive damages of not less than $1 billion, as well as a declaration that Peabody's lease and contract rights to mine coal on Navajo Nation lands should be terminated. SCE joined Peabody's motion to strike the Navajo Nation's complaint. In addition, SCE and other defendants filed motions to dismiss.

Some of the issues included in this case were addressed by the United States Supreme Court in a separate legal proceeding filed by the Navajo Nation in the Court of Federal Claims against the United States Department of Interior. In that action, the Navajo Nation claimed that the Government breached its fiduciary duty concerning negotiations relating to the coal lease involved in the Navajo Nation's lawsuit against SCE and Peabody. On March 4, 2003, the Supreme Court concluded, by majority decision, that there was no breach of a fiduciary duty and that the Navajo Nation did not have a right to relief against the Government. Based on the Supreme Court's analysis, on April 28, 2003, SCE filed a motion to dismiss or, in the alternative, for summary judgment in the D.C. District Court action. The motion remains pending.

The Federal Circuit Court of Appeals, acting on a suggestion on remand filed by the Navajo Nation, held in a October 24, 2003 decision that the Supreme Court's March 24, 2003 decision was focused on three specific statutes or regulations and therefore did not address the question of whether a network of other statutes, treaties and regulations imposed judicially enforceable fiduciary duties on the United States during the time period in question. The Government and the Navajo Nation both filed petitions for rehearing of the October 24, 2003 Court of Appeals decision. Both petitions were denied on March 9, 2004.

SCE cannot predict with certainty the outcome of the 1999 Navajo Nation's complaint against SCE, the impact of the Supreme Court's decision in the Navajo Nation's suit against the Government on this complaint, or the impact of the complaint on the operation of Mohave beyond 2005.

San Onofre Steam Generators

Like other nuclear power plants with steam generators of the same design and material properties, San Onofre Units 2 and 3 have experienced degradation in their steam generators. Based on industry experience and analysis of recent inspection data, SCE has determined that the existing San Onofre Unit 2 and 3 steam generators may not enable continued reliable operation of the units beyond their scheduled refueling outages in 2009–2010. SCE currently estimates that the cost of replacing the steam generators would be about $680 million, of which SCE's 75% share would be about $510 million. On February 27, 2004, SCE asked the CPUC to issue a decision by July 2005 finding that it is reasonable for SCE to replace the San Onofre Unit 2 and 3 steam generators and establishing appropriate ratemaking for the replacement costs. In its application, SCE stated that the San Onofre operating agreement requires unanimous approval of all co-owners for the costs of the steam generator replacement to be included in the capital budget for Units 2 and 3 and, therefore, SCE must have the approval of its co-owners to go forward as planned, which approval currently is lacking. Because SCE will need to enter into commitments in 2004 to obtain timely delivery of replacement steam generators, SCE also asked the CPUC to create a memorandum account by September 2004 for SCE to recover initial costs of up to $50 million if the replacement project ultimately is not approved by the CPUC or co-owner approval is not obtained. If the CPUC finds investment in the steam generators to be reasonable and cost effective and the steam generator replacement takes place, SCE's investment should be reflected in retail rates for recovery over the remaining useful life of the plants. SCE currently does not expect that it would proceed with replacement of the San Onofre Units 2 and 3 steam generators without CPUC approval of reasonable cost recovery.

Palo Verde Steam Generators

The steam generators at the Palo Verde Nuclear Generating Station (Palo Verde), in which SCE owns a 15.8% interest, have the same design and material properties as the San Onofre units. During 2003, the Palo Verde Unit 2 steam generators were replaced. In addition, the Palo Verde owners have approved the manufacture of two additional sets of steam generators for installation in Units 1 and 3. The Palo Verde owners expect that these steam generators will be installed in Units 1 and 3 in the 2005 to 2008 time frame. SCE's share of the costs of manufacturing and installing all the replacement steam generators at Palo Verde is estimated to be about $110 million; SCE plans to seek recovery of that amount through the rate-making process.

MISSION ENERGY HOLDING COMPANY
and EDISON MISSION ENERGY

MEHC AND EME: MANAGEMENT OVERVIEW

MEHC as a Holding Company

MEHC is the holding company of EME which, itself, operates through its subsidiaries and affiliates which are engaged in the business of owning or leasing, operating and selling energy and capacity from electric power generation facilities worldwide. MEHC has no business activities other than through its ownership interest in EME. During 2001, MEHC issued $800 million of senior secured notes and borrowed $385 million under a term loan. The senior secured notes and the term loan are secured by a first priority security interest in EME's common stock. MEHC's ability to honor its obligations under the senior secured notes and the term loan is entirely dependent upon the receipt of dividends from EME and receipt of tax-allocation payments from MEHC's parent, Edison Mission Group Inc., and ultimately Edison International (see "MEHC and EME: Liquidity—EME's Liquidity as a Holding Company—Intercompany Tax-Allocation Payments"). Dividends from EME are limited based on its earnings and cash flow, terms of restrictions contained in EME's contractual obligations (including its corporate credit facility), EME's charter documents, business and tax considerations, and restrictions imposed by applicable law. MEHC did not receive any distributions from EME during 2003.

The lenders under MEHC's $385 million term loan due in 2006 have the right to require MEHC to repurchase up to $100 million of principal amount at par on July 2, 2004 (referred to as the "Term Loan Put-Option"). In order for MEHC to have sufficient cash in the event of an exercise of a significant portion, or all, of the Term Loan Put-Option, MEHC would require additional cash from dividends from EME, or would need to either extend the effective date of the Term Loan Put-Option or extend or refinance the term loan. Dividends from EME are currently limited as described in "MEHC and EME: Liquidity—Financial Ratios—Ability of EME to Pay Dividends."

EME Introduction

EME is a holding company which operates primarily through its subsidiaries and affiliates which are engaged in the business of owning or leasing, operating and selling energy and capacity from electric power generation facilities worldwide. EME's subsidiaries or affiliates have typically been formed to own all of or an interest in one or more power plants and ancillary facilities, with each plant or group of related plants being individually referred to by EME as a project. EME also owns a 51% interest in Contact Energy, an integrated energy company located in New Zealand. As of December 31, 2003, EME's subsidiaries and affiliates owned or leased interests in 28 projects, of which 14 are domestic and 14 (including EcoEléctrica) are international.

EME has financed the development and construction or acquisition of its projects by contributions of equity from EME and the incurrence of so-called project financed debt obligations by the subsidiaries and affiliates owning the operating facilities. These project level debt obligations are generally structured as nonrecourse to EME, with several exceptions, including EME's guarantee of the Powerton and Joliet leases as part of a refinancing of indebtedness incurred by its project subsidiary to purchase the Illinois plants. As a result, these project level debt obligations have structural priority with respect to revenue, cash flows and assets of the project companies over debt obligations incurred by EME, itself. In this regard, EME has, itself, borrowed funds to make the equity contributions required of it for its projects and for general corporate purposes. Since EME does not, itself, directly own any revenue producing generation facilities, it depends for the most part on cash distributions from its projects to meet its debt

service obligations, to pay for general and administrative expenses and to pay dividends to its parent, MEHC.

Distributions to EME from projects are generally only available after all current debt service obligations at the project level have been paid and are further restricted by contractual restrictions on distributions included in the documentation evidencing the project level debt obligations. Because of such a contractual constraint, distributions to EME from cash generated from the Illinois plants has been restricted since October 1, 2002 due to a downgrade of the credit rating of this project's debt to below investment grade. EME also is currently subject to constraints on its ability to make distributions to its parent, MEHC. For a description of the most significant contractual constraints under the projects, see "MEHC and EME: Liquidity—Dividend Restrictions in Major Financings."

EME's project portfolio may be grouped into two categories: contracted plants and merchant plants. At December 31, 2003, EME owned 25 projects that sell a majority of their power to customers under long-term sales arrangements (greater than 5 years) consisting of power-purchase agreements or hedge contracts (in the case of Contact Energy, sales are made through its retail electricity business). While these projects involve a number of risks, their long-term sales arrangements generally provide a stable and predictable revenue stream which results in reasonably predictable cash distributions to EME.

EME owns three projects (the Illinois plants, the Homer City facilities and the First Hydro Power Plants) which operate in whole or in part without long-term sales arrangements (representing approximately 70% of EME's project portfolio based on capacity). Although the generation of the Illinois plants was at the time of their acquisition in late 1999 subject to sale under contracts with Exelon Generation, the amount of capacity and energy subject to sale under these contracts has been gradually reduced in the ensuing contract years, and these contracts will expire at the end of 2004. Output from merchant plants (as well as excess output from contracted plants) which is not committed to be sold under long-term sales arrangements is subject, in terms of price and volume, to market forces which determine the actual amount and price of power sold from these power plants. A description of these market forces and the risks associated with them is included under "MEHC and EME: Market Risk Exposures."

EME Industry Developments

Beginning in 2001, a number of significant developments adversely affected merchant generators (companies that sell a majority of their generation into wholesale energy markets), including EME. These developments included lower prices and greater volatility in wholesale energy markets both in the United States and United Kingdom, significant declines in the credit ratings of most major market participants, decreased availability of debt financing or refinancing, and a resulting decline of liquidity in the energy markets due to growing concern about the ability of counterparties to perform their obligations.

Overview of EME's 2003 Operating Performance

EME's 2003 operating performance was significantly improved over 2002. A number of important items affected this performance, including the following:

- Power prices in PJM rebounded in 2003 from their depressed prices in 2002 driven largely by higher natural gas prices in the United States as discussed further below. The 24-hour PJM market price (at the Homer City busbar) increased 37% from $25.63 per megawatt hour in 2002 to $35.08 per megawatt hour in 2003. The increase in market price substantially improved the profitability of the Homer City plant.

- Higher natural gas prices also resulted in improved profitability of EME's interest in Four Star Oil & Gas Company and the Big 4 projects.

- EME achieved an availability factor of 89% across its project portfolio and a forced outage rate of 5% compared to a benchmark (NERC-GD) availability factor of 85% and a forced outage rate of 7% for an equivalent project portfolio.

- The Paiton project debt was restructured following on the late 2002 revisions in its power-purchase contracts.

- The Sunrise project completed Phase 2 of its development ahead of schedule and, thus, was able to generate additional capacity revenue during the summer of 2003.

- Contact Energy continued to expand its retail customer base which, together with increases in retail prices and higher sales of wholesale natural gas, collectively improved the profitability of this subsidiary.

- On the negative side, EME recorded three asset impairment charges (pre-tax) during 2003:

  - $245 million related to the impairment of eight small peaking units of the Illinois plants resulting from a revised long-term outlook for capacity revenue from these units. The lower capacity revenue outlook is the result of a number of factors, including higher forecasted long-term natural gas prices and the current oversupply of generation in the Mid-America Interconnected Network (MAIN) region;

  - $53 million related to the write-down of EME's investment in the Brooklyn Navy Yard project due to its planned disposition; and

  - $6 million related to the write-down of EME's investment in the Gordonsville project, which was subsequently sold in 2003.

- Also on the negative side, the amount of capacity sold to Exelon Generation from the Illinois plants decreased significantly from 2002 as discussed further below.

In 2003, the Illinois plants had 4,739 MW of contracted capacity (to Exelon Generation) and 3,109 MW of uncontracted capacity available for sale in the merchant generation market, compared with 8,987 MW of contract capacity and 300 MW of such uncontracted capacity in 2002. The reduction in contracted generating capacity decreased revenue from Exelon Generation as a percentage of the Illinois plants' total energy and capacity revenue to 68% in 2003 from 99% in each of 2002 and 2001. The reduction in contracted capacity resulted in a decrease of capacity revenue of $222 million, partially offset by an increase of $127 million in energy revenue from sales of increased merchant generation. Prices realized from sales of merchant generation were significantly higher than energy prices payable under the power-purchase agreements with Exelon Generation. EME expects that capacity prices in the MAIN region will, in the near term, be significantly lower than those payable under the existing agreements with Exelon Generation (due to generation overcapacity conditions in the MAIN region market), but also expects that merchant energy prices will, in the near term, be higher than those currently received under the existing agreements with Exelon. See "MEHC and EME: Market Risk Exposures" for further discussion of forward market prices in the MAIN region.

A significant factor affecting merchant generators in 2003 was the substantial increase in the price of natural gas, especially when compared with the less volatile cost of other fuels, such as coal. During 2003, natural gas prices at Henry Hub (a major natural gas trading hub) averaged $5.48 per million British Thermal Units, commonly referred to as MMBtu, compared to $3.37 per MMBtu for 2002. Based upon data from NYMEX as of December 26, 2003, the calendar year 2004 forward natural gas price at

Henry Hub was $5.45 per MMBtu. Increases in natural gas prices during 2003 resulted in higher wholesale electricity prices (since natural gas is the primary fuel for many generating plants). This increase in natural gas prices was a positive factor for low-cost merchant coal facilities (such as a majority of EME's domestic merchant plants) in markets dominated by gas-fired plants and somewhat positive for such facilities in those markets more dependent on low-cost coal and nuclear facilities. In contrast, for gas-fired merchant generators that sell their power into markets dominated by low-cost coal and nuclear power plants, the increase in natural gas prices adversely affected their results. These conditions adversely affected the Collins Station and small peaking units in Illinois as discussed above.

EME's Restructuring Plan

EME has undertaken a four-step restructuring plan with the goal of reducing consolidated indebtedness. The four-step restructuring plan includes:

1) *Repayment of the December 2003 debt maturity at Edison Mission Midwest Holdings and other near term debt maturities.*

   In December 2003, EME's subsidiary, Mission Energy Holding International, Inc., received funding under a three-year, $800 million secured loan which was used, together with other internally generated cash, to repay $1.2 billion of EME and Edison Mission Midwest Holdings indebtedness. See further discussion under "MEHC and EME: Liquidity—Key Financing Developments."

2) *Refinancing indebtedness associated with the Illinois Plants.*

   EME intends to arrange a refinancing of indebtedness associated with the Illinois plants. This consists of $693 million of debt due at Edison Mission Midwest Holdings and the planned termination of the Collins Station lease. See "MEHC and EME: Liquidity—Key Financing Developments—EME's Subsidiary Financing Plans—Agreement in Principle to Terminate the Collins Station Lease." EME expects that the refinancing of these arrangements will be completed well in advance of December 2004, but there is no assurance that this will be accomplished.

3) *Selling some or all of its international operations.*

   EME has engaged investment bankers to market for sale its international project portfolio. The marketing efforts commenced during the first quarter of 2004. Completion of the sale of some or all of EME's international project portfolio is contingent on receiving acceptable offers with respect to both price and terms and conditions.

4) *Using the proceeds of asset sales to reduce consolidated indebtedness.*

   Assuming a successful sale of its international assets and completion of the sale of identified domestic projects, EME plans to use the proceeds first to repay the $800 million term loan described above and, with any additional proceeds received, to retire other consolidated indebtedness.

Expansion of PJM in Illinois

For the Illinois plants to achieve their optimal value, it is important that efficient and fair markets exist in the Midwest region. The Illinois plants are located within the service territory of Exelon Generation's affiliate, Commonwealth Edison (ComEd), which has made a filing with the FERC to join the PJM System effective May 1, 2004. Although FERC has indicated its general approval for ComEd and American Electric Power (AEP) to join PJM if certain conditions designed to foster broad regional markets in the Midwest are met, the integration of AEP into PJM has been stalled due to the opposition of

the states of Virginia and Kentucky. While EME and Midwest Generation have supported the entry of ComEd and AEP into PJM at the same time, they have nevertheless opposed ComEd's entry into PJM without AEP on numerous grounds, including the importance of the AEP system to the proper functioning of the markets administered by PJM. This issued is currently pending before FERC.

If the integration of ComEd into PJM standing alone is allowed by the FERC to proceed on May 1, 2004, the Illinois plants will become subject to PJM's market rules, including those designed to mitigate generation market power, which PJM has indicated may be applied as if the market is limited only to the generation within the ComEd footprint. (By contrast, PJM has stated to the FERC that market mitigation measures will likely not be necessary from and after the integration of AEP into PJM.) EME and Midwest Generation have strongly opposed this limited view of the market with the FERC, and the matter is pending decision in connection with the ComEd/PJM integration filing. If this opposition is unsuccessful, the price for sales of energy from such plants (during the period prior to AEP's integration) not sold pursuant to bilateral agreement could be capped at their marginal operating cost to produce such energy plus ten percent, under the proposed rules of the PJM Market Monitor.

Contracting Strategy

EME's goal is to reduce the volatility of its earnings and cash flow and, thus, improve the predictability of operating results. To do this, EME's plans to implement a layered contracting strategy for forward sales from the Illinois plants and the Homer City facilities. A layered contracting strategy means that EME's marketing subsidiary, Edison Mission Marketing & Trading, plans to enter into a number of forward contracts diversified by counterparty, contract term and generation product to reduce risk and enhance the predictability of revenue. Implementation of this strategy is dependent on a number of factors, such as a reduction in the current oversupply of generation, the rate of demand growth, and agreement between counterparties of reasonable credit support undertakings.

MEHC AND EME: LIQUIDITY

At December 31, 2003, MEHC and its subsidiaries had cash and cash equivalents of $654 million. MEHC's consolidated debt at December 31, 2003 was $7.4 billion, including $693 million of debt maturing on December 15, 2004 which is owed by EME's largest subsidiary, Edison Mission Midwest Holdings. In addition, EME's subsidiaries have $6.7 billion of long-term lease obligations that are due over a period ranging up to 31 years.

The following discussion of liquidity is organized in the following sections:

- MEHC's Liquidity
- Key Financing Developments
- 2004 Capital Expenditures
- EME's Credit Ratings
- EME's Liquidity as a Holding Company
- Dividend Restrictions in Major Financings
- Financial Ratios

MEHC's Liquidity

MEHC's ability to honor its obligations under the senior secured notes and the term loan, and to pay overhead is entirely dependent upon the receipt of dividends from EME and receipt of tax-allocation payments from MEHC's parent, Edison Mission Group, and ultimately Edison International (see "—EME's Liquidity as a Holding Company—Intercompany Tax-Allocation Payments"). Dividends from EME are limited based on its earnings and cash flow, terms of restrictions contained in EME's contractual obligations (including its corporate credit facility), EME's charter documents, business and tax considerations, and restrictions imposed by applicable law. MEHC did not receive any distributions from EME during 2003.

At December 31, 2003, MEHC had cash and cash equivalents of $150 million (excluding amounts held by EME and its subsidiaries). The lenders under MEHC's $385 million term loan due in 2006 have the right to require MEHC to repurchase up to $100 million of principal amount at par on July 2, 2004 (referred to as the "Term Loan Put-Option"). In order for MEHC to have sufficient cash in the event of an exercise of a significant portion, or all, of the Term Loan Put-Option, MEHC would require additional cash from dividends from EME, or would need to either extend the effective date of the Term Loan Put-Option or extend or refinance the term loan. The timing and amount of dividends from EME and its subsidiaries may be affected by many factors beyond MEHC's control. Dividends from EME are currently limited as described in "—Financial Ratios—Ability of EME to Pay Dividends."

Key Financing Developments

On December 11, 2003, EME's subsidiary, Mission Energy Holdings International, received funding under a three-year, $800 million secured loan from Citigroup, Credit Suisse First Boston, JPMorganChaseBank, and Lehman Brothers. Interest on this secured loan is based on LIBOR (with a LIBOR floor of 2%) plus 5%. After payment of transaction expenses, a portion of the net proceeds from this financing was used to make an equity contribution of $550 million to Edison Mission Midwest Holdings which, together with cash on hand, was used to repay Edison Mission Midwest Holdings' $781 million indebtedness due December 11, 2003. The remaining net proceeds from this financing were used to make a deposit of cash collateral of approximately $67 million under the new letter of credit facility described below and to repay approximately $160 million of indebtedness of a foreign subsidiary under the Coal and Capex facility guaranteed by EME. Mission Energy Holdings International owns substantially all of EME's international operations through its subsidiary, MEC International B.V. As security for this loan, Mission Energy Holdings International, directly, and through its subsidiaries, pledged approximately 65% of its ownership interest in MEC International B.V. See "MEHC and EME: Management Overview" for discussion of the plan to sell off some of or all of EME's international projects.

On December 11, 2003, EME's subsidiary, Midwest Generation EME, LLC, entered into a three-year, $100 million letter of credit facility with Citibank, N.A., as Issuing Bank. Under the terms of this letter of credit facility, Midwest Generation EME is required to deposit cash in a bank account in order to cash collateralize any letters of credit that may be outstanding under it. The bank account is pledged to the Issuing Bank. On December 11, 2003, EME canceled $67 million of the commitment under its existing line of credit and was relieved of its reimbursement obligations with respect to the same amount of letters of credit issued thereunder. Concurrently, such letters of credit were issued under Midwest Generation EME's new letter of credit facility, and Midwest Generation EME made a deposit of cash collateral in the amount of $67 million for this purpose. The funds for this deposit were obtained as part of the financing referred to above. At December 31, 2003, $47 million of letters of credit were outstanding under Midwest Generation EME's letter of credit facility. Midwest Generation EME owns 100% of Edison Mission Midwest Holdings, which in turn owns 100% of Midwest Generation LLC.

EME's Subsidiary Financing Plans

Agreement in Principle to Terminate the Collins Station Lease

Midwest Generation operates the Collins Station under a long-term lease. See "Off-Balance Sheet Transactions—EME's Off-Balance Sheet Transactions—Sale-Leaseback Transactions" for detail of the lease of the Collins Station. Due in part to higher long-term natural gas prices and the current oversupply of generation in the MAIN region, Midwest Generation does not believe the Collins Station is economically competitive in the current marketplace. In light of this, Midwest Generation has agreed in principle with the lease equity investor to terminate the Collins Station lease. The agreement in principle sets forth specified conditions required for the termination, including Midwest Generation successfully borrowing funds to finance the repayment of Collins Station lease debt of $774 million and settlement of Midwest Generation's termination liability with the lease equity investor. There is no assurance that the agreement in principle will result in termination of the Collins Station lease. If the termination occurs, Midwest Generation will take title to the Collins Station and, subject to its contractual obligation to Exelon Generation, plans to subsequently abandon the Collins Station or sell it to a third party.

If Midwest Generation completes the lease termination and subsequently abandons the Collins Station, EME expects to record a pre-tax loss of approximately $1 billion (approximately $620 million after tax). This loss will reduce EME's net worth (using December 31, 2003) from $1.9 billion to approximately $1.3 billion. To avoid the possibility of covenant defaults which could arise from a decline in net worth, EME plans to take the following actions before or simultaneously with the Collins Station lease termination:

- replace its $145 million corporate credit facility with a new secured credit facility;
- repay the $28 million due under the Coal and Capex facility (guaranteed by EME); and
- eliminate or modify the net worth covenant in its guaranty of the Powerton-Joliet lease.

If Midwest Generation completes the termination of the Collins Station lease followed by abandonment or sale to a third party, EME anticipates that the termination payment would result in a substantial income tax deduction. Because of these arrangements, EME does not expect that termination of the Collins Station lease will have a material adverse effect on its liquidity. If the lease termination does not occur, the terms of the lease will remain in effect and Midwest Generation will seek to restructure the lease with the lease equity investor.

Edison Mission Midwest Holdings

EME's wholly owned subsidiary, Edison Mission Midwest Holdings, has $693 million of debt maturing on December 15, 2004 which will need to be repaid or refinanced. Edison Mission Midwest Holdings is currently not expected to have sufficient cash to repay the $693 million debt due in December 2004, and there is no assurance that it will be able to refinance this debt obligation on similar terms and rates as the existing debt, on commercially reasonable terms, on the terms permitted under the financing documents entered into by MEHC in July 2001, or under the guarantee entered into by Midwest Generation EME in December 2003, or at all. MEHC's independent auditors' audit opinion for the year ended December 31, 2003 contains an explanatory paragraph that indicates the consolidated financial statements are prepared on the basis that MEHC will continue as a going concern and that the uncertainty about Edison Mission Midwest Holdings' ability to repay or refinance this obligation raises substantial doubt about MEHC's ability to continue as a going concern. Accordingly, the consolidated financial statements do not include any adjustments that might result from the resolution of this uncertainty.

A failure to repay or refinance Edison Mission Midwest Holdings' $693 million of debt as required by its terms would result in an event of default under the Edison Mission Midwest Holdings financing documents. Furthermore, these events would trigger cross-defaults under agreements to which Edison Mission Midwest Holdings and Midwest Generation are parties, including the Collins, Powerton and Joliet leases. An acceleration of debt and lease payments due under these agreements could result in a substantial claim for termination value under the EME guarantee of the Powerton and Joliet leases and could result in a default under EME's financing arrangements. A default by EME on its financing arrangements or a default by one of its subsidiaries on indebtedness considered under the MEHC financing documents as having recourse to EME is likely to result in a default under the MEHC financing documents. These events could make it necessary for MEHC or EME or both to file a petition for reorganization under Chapter 11 of the United States Bankruptcy Code.

2004 Capital Expenditures

The estimated construction expenditures of EME's subsidiaries for 2004 are $78 million. These expenditures are planned to be financed by existing subsidiary credit agreements and cash generated from their operations.

EME's Credit Ratings

Overview

Credit ratings for EME and its subsidiaries, Edison Mission Midwest Holdings and Edison Mission Marketing & Trading, are as follows:

	Moody's Rating	S&P Rating
EME	B2	B
Edison Mission Midwest Holdings	Ba3	B
Edison Mission Marketing & Trading	Not Rated	B

On October 28, 2003, Standard & Poor's Ratings Service downgraded EME's senior unsecured credit rating to B from BB-. Standard & Poor's also lowered the credit ratings of EME's wholly owned indirect subsidiaries, Edison Mission Midwest Holdings (syndicated loan facility to B from BB-) and Edison Mission Marketing & Trading (corporate credit rating to B from BB-). Standard & Poor's removed the ratings from CreditWatch with negative implications on December 12, 2003, following the repayment of $781 million of debt by Edison Mission Midwest Holdings; however, the outlook remains negative. In addition, Moody's Investors Service has assigned a negative rating outlook for EME and Edison Mission Midwest Holdings.

These ratings actions did not trigger any defaults under EME's credit facilities or those of the other affected entities. See "—EME's Credit Ratings—Credit Ratings of Edison Mission Midwest Holdings" for a discussion of the impact of the ratings action on Edison Mission Midwest Holdings. EME does not have any "rating triggers" contained in subsidiary financings that would result in EME being required to make equity contributions or provide additional financial support to its subsidiaries.

The credit ratings of EME are below investment grade and, accordingly, EME has agreed to provide collateral in the form of cash and letters of credit for the benefit of counterparties for its price risk management and domestic trading activities related to accounts payable and unrealized losses ($65 million as of February 27, 2004). EME has also provided collateral for a portion of its United Kingdom trading activities. To this end, EME's subsidiary, Edison Mission Operation and Maintenance

Limited, has obtained a cash collateralized credit facility, under which letters of credit totaling £20 million have been issued as of February 27, 2004.

EME anticipates that sales of power from its Illinois plants, Homer City facilities and First Hydro plants in the United Kingdom may require additional credit support, depending upon market conditions and the strategies adopted for the sale of this power. Changes in forward market prices and margining requirements could further increase the need for credit support for the price risk management and trading activities related to these projects. EME currently projects the potential working capital required to support its price risk management and trading activity to be between $100 million and $200 million from time to time.

EME 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 further. EME 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.

Credit Ratings of Edison Mission Midwest Holdings

As a result of Edison Mission Midwest Holdings' credit rating being below investment grade since October 2002, provisions in the agreements binding on Edison Mission Midwest Holdings and Midwest Generation have restricted the ability of Edison Mission Midwest Holdings to make distributions to its parent company, thereby eliminating distributions to EME. The provisions in the agreements binding on Edison Mission Midwest Holdings required it to deposit, on a quarterly basis, 100% of its excess cash flow as defined in the agreements into a cash flow recapture account held and maintained by the collateral agent. In accordance with these provisions, Edison Mission Midwest Holdings deposited $246 million into the cash flow recapture account in 2002 and 2003.

As a result of the October 28, 2003 Standard & Poor's downgrade of Edison Mission Midwest Holdings to B from BB-, the cash on deposit in the cash flow recapture account ($246 million) was required to be used to prepay Edison Mission Midwest Holdings' indebtedness, with the amount of such prepayment applied ratably to the $911 million and $808 million tranches thereof. Therefore, on October 29, 2003, $130 million from the cash flow recapture account was applied to the $911 million tranche, and $116 million to the $808 million tranche, thereby reducing Edison Mission Midwest Holdings' debt obligations to $781 million and $693 million, respectively. Subsequently, Edison Mission Midwest Holdings repaid the $781 million tranche in full on December 11, 2003. In the future, so long as Edison Mission Midwest Holdings' ratings remain at the current level or lower, amounts of excess cash flow deposited in the cash flow recapture account at the end of each calendar quarter will be used upon deposit to prepay amounts then outstanding under the $693 million bank facility. There was no change to the cost of borrowings for Edison Mission Midwest Holdings as a result of the downgrade.

As part of the sale-leaseback of the Powerton and Joliet power stations, Midwest Generation loaned the proceeds ($1.4 billion) to EME in exchange for promissory notes in the same aggregate amount. Debt service payments by EME on the promissory notes may be used by Midwest Generation to meet its payment obligations under these leases in whole or part. Furthermore, EME has guaranteed the lease obligations of Midwest Generation under these leases. EME's obligations under the promissory notes payable to Midwest Generation are general corporate obligations of EME and are not contingent upon receiving distributions from Edison Mission Midwest Holdings. Accordingly, EME must continue to make payments under the intercompany notes notwithstanding that Edison Mission Midwest Holdings is not permitted to make distributions to EME. If EME were not able to make the loan payments, it would result in a default under the financing documents to which Edison Mission Midwest Holdings is a party and could result in a default under EME's financing arrangements. This could have a material adverse effect on the results of operations and cash flow of MEHC and EME. See "—Dividend Restrictions in

Major Financings—Edison Mission Midwest Holdings Co. (Illinois Plants)" for a discussion of implications for the Powerton and Joliet leases.

Credit Rating of Edison Mission Marketing & Trading

Pursuant to the Homer City sale-leaseback documents, a below investment grade credit rating of Edison Mission Marketing & Trading restricts the ability of EME Homer City Generation L.P. to enter into permitted trading activities, as defined in the documents, with Edison Mission Marketing & Trading to sell forward the output of the Homer City facilities. 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 of the output from the Homer City facilities through Edison Mission Marketing & Trading, 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 Edison Mission Marketing & Trading; or (2) Edison Mission Marketing & Trading 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, 2004. EME Homer City continues to be in compliance with the terms of the consent, although as a result of the downgrade of Edison Mission Marketing & Trading's corporate credit rating to B from BB-, the consent is now revocable. The owner participant has not indicated that it intends to revoke the consent; however, there can be no assurance that it will not do so in the future. Revocation of the consent would not affect trades between Edison Mission Marketing & Trading and EME Homer City that had been entered into while the consent was still in effect. EME is permitted to sell the output of the Homer City facilities into the spot market at any time. See "MEHC and EME: Market Risk Exposures—Commodity Price Risk—Homer City Facilities."

EME's Liquidity as a Holding Company

Overview

EME has a $145 million corporate credit facility that expires on September 17, 2004. At December 31, 2003, EME had borrowing capacity of $145 million and corporate cash and cash equivalents of $179 million. During 2003, EME's cash position increased primarily due to an increase of distributions received from its consolidated subsidiaries and initial distributions from the Sunrise project upon completion of project financing. The timing and amount of distributions from EME's subsidiaries may be affected by many factors beyond its control. See "—EME's Liquidity as a Holding Company—Historical Distributions Received by EME" and "—Dividend Restrictions in Major Financings." In addition, the right of EME to receive tax-allocation payments, and the timing and amount of tax-allocation payments received by EME are subject to factors beyond EME's control. See "—EME's Liquidity as a Holding Company—Intercompany Tax-Allocation Payments."

EME's corporate credit facility provides credit available in the form of cash advances or letters of credit. At December 31, 2003, there were no cash advances outstanding or letters of credit outstanding under the credit facility. In addition to the interest payments, EME pays a facility fee determined by its long-term credit ratings (1.00% at December 31, 2003) on the credit facility independent of the level of borrowings. Under the credit agreement governing its credit facility, EME has agreed to maintain an interest coverage ratio that is based on cash received by EME, including tax-allocation payments, cash disbursements and interest paid. At December 31, 2003, EME met this interest coverage ratio. The interest coverage ratio in the ring-fencing provisions of EME's certificate of incorporation and bylaws remains relevant for determining EME's ability to make distributions. See "—Financial Ratios—EME's Interest Coverage Ratio."

Historical Distributions Received By EME

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

In millions December 31,	2003	2002
Domestic Projects		
Distributions from Consolidated Operating Projects:		
EME Homer City Generation L.P. (Homer City facilities)(1)	$ 128	$ —
Holding companies of other consolidated operating projects	1	2
Distributions from Unconsolidated Operating Projects:		
Edison Mission Energy Funding Corp. (Big 4 Projects)(2)	98	137
Four Star Oil & Gas Company	21	21
Sunrise Power Company(3)	69	—
Holding companies for Westside projects	25	42
Holding companies of other unconsolidated operating projects	7	10
Total Distributions from Domestic Projects	$ 349	$ 212
International Projects (Mission Energy Holdings International)		
Distributions from Consolidated Operating Projects:		
First Hydro Holdings (First Hydro project)	$ 18	$ —
Loy Yang B	39	27
Doga	18	47
Contact Energy	16	12
Valley Power	8	—
Kwinana	4	6
Distributions from Unconsolidated Operating Projects:		
ISAB Energy	27	1
IVPC4 (Italian Wind project)	10	33
Derwent	3	2
Paiton(4)	9	—
Tri Energy	4	3
Holding companies of other unconsolidated operating project	2	8
Total Distributions from International Projects	$ 158	$ 139
Total Distributions	$ 507	$ 351

(1) Excludes $34 million distributed by EME Homer City from additional cash on hand due to accelerated payments received from Edison Mission Marketing & Trading.

(2) The Big 4 projects are comprised of investments in the Kern River project, Midway-Sunset project, Sycamore project and Watson project. Distributions do not include either capital contributions made during the California energy crisis or the subsequent return of such capital. Distributions reflect the amount received by EME after debt service payments by Edison Mission Energy Funding Corp.

(3) Includes $59 million of the $151 million proceeds from the Sunrise project financing. The remaining $92 million EME has classified as a return of capital.

(4) Represents a return of capital received as part of completion of the restructuring of the Paiton debt obligations.

Total distributions to EME increased between 2003 and 2002 due to:

- Distributions from Homer City due to increased generation and higher energy prices. The project did not make any distributions in 2002 because of outages in the first half of 2002;
- Distribution from the First Hydro project in May 2003. The project did not make any distributions in 2002 due to restrictions under its bond indenture;
- Initial distributions from the Sunrise project upon completion of project financing; and
- Initial partner distributions from the ISAB Energy project.

Partially offset by:

- Lower distributions from the Big 4 projects (in March 2002, SCE paid the Big 4 projects their past due accounts receivable that accrued during the California energy crisis);
- Lower distributions from the Westside projects due to payments of past due accounts receivable from Pacific Gas & Electric in 2002 that accrued during the California energy crisis; and
- 2003 distributions from the Doga and Italian Wind projects represented twelve months of operating cash flow, whereas the initial distributions in 2002 included cash flow from prior years.

Intercompany Tax-Allocation Payments

MEHC and EME are included in the consolidated federal and combined state income tax returns of Edison International and are eligible to participate in tax-allocation payments with other subsidiaries of Edison International. These arrangements depend on Edison International continuing to own, directly or indirectly, at least 80% of the voting power of the stock of MEHC and EME and at least 80% of the value of such stock. The arrangements are subject to the terms of tax-allocation and payment agreements among Edison International, MEHC, EME, and other Edison International subsidiaries. The agreements to which MEHC and EME are parties may be terminated by the immediate parent company of MEHC at any time, by notice given before the first day of the first tax year with respect to which the termination is to be effective. However, termination does not relieve any party of any obligations with respect to any tax year beginning prior to the notice. MEHC became a party to the tax-allocation agreement with Edison Mission Group on July 2, 2001, when it became part of the Edison International consolidated filing group. EME and MEHC have historically received tax-allocation payments related to domestic net operating losses incurred by EME and MEHC. The right of MEHC and EME to receive and the amount and timing of tax-allocation payments are dependent on the inclusion of MEHC and EME, respectively, in the consolidated income tax returns of Edison International and its subsidiaries, the amount of net operating losses and other tax items of MEHC, EME, its subsidiaries, and other subsidiaries of Edison International and specific procedures regarding allocation of state taxes. MEHC and EME receive tax-allocation payments for tax losses when and to the extent that the consolidated Edison International group generates sufficient taxable income in order to be able to utilize MEHC's tax losses or the tax losses of EME in the consolidated income tax returns for Edison International and its subsidiaries. MEHC received $61 million and $89 million in tax-allocation payments from Edison International during 2003 and 2002, respectively. EME received $112 million and $395 million in tax-allocation payments from Edison International during 2003 and 2002, respectively. In the future, based on the application of the factors cited above, MEHC and EME may be obligated during periods it generates taxable income to make payments under the tax-allocation agreements.

Dividend Restrictions in Major Financings

General

Each of EME's direct or indirect subsidiaries is organized as a legal entity separate and apart from EME and its other subsidiaries. Assets of EME's subsidiaries are not available to satisfy EME's obligations or the obligations of any of its other subsidiaries. However, unrestricted cash or other assets that are available for distribution may, subject to applicable law and the terms of financing arrangements of the parties, be advanced, loaned, paid as dividends or otherwise distributed or contributed to EME or to its subsidiary holding companies. EME itself has restrictions on its ability to pay dividends under its organizational documents and its corporate credit facility. See "—Financial Ratios—Ability of EME to Pay Dividends."

Set forth below is a description of covenants binding EME's principal subsidiaries that may restrict the ability of those entities to make distributions to EME directly or indirectly through the other holding companies owned by EME.

Edison Mission Midwest Holdings Co. (Illinois Plants)

Edison Mission Midwest Holdings Co. is the borrower under a $1.9 billion credit facility with a group of commercial banks. Amounts outstanding under this facility have been reduced to $693 million as of December 31, 2003. The funds borrowed under this facility were used to fund the acquisition of the Illinois plants and provide working capital to such operations. Midwest Generation, a wholly owned subsidiary of Edison Mission Midwest Holdings, owns or leases and operates the Illinois plants. As part of the original acquisition, Midwest Generation entered into a sale-leaseback transaction for the Collins Station, which Edison Mission Midwest Holdings guarantees, and then subsequently entered into sale-leaseback transactions for the Powerton Station and the Joliet Station in August 2000. In order for Edison Mission Midwest Holdings to make a distribution, Edison Mission Midwest Holdings must be in compliance with the covenants specified in these agreements, including maintaining a minimum credit rating. Because Edison Mission Midwest Holdings' credit rating is below investment grade, no distributions can currently be made by Edison Mission Midwest Holdings to its parent company, and ultimately to EME, at this time. See "—EME's Credit Ratings."

Edison Mission Midwest Holdings must maintain a debt service coverage ratio for the prior twelve-month period of at least 1.50 to 1 as long as the power-purchase agreements with Exelon Generation represent 50% or more of Edison Mission Midwest Holdings' and its subsidiaries' revenue. If the power-purchase agreements with Exelon Generation represent less than 50% of Edison Mission Midwest Holdings' and its subsidiaries' revenue, it must maintain a debt service coverage ratio of at least 1.75 to 1. In addition, Edison Mission Midwest Holdings must maintain a debt-to-capital ratio no greater than 0.60 to 1. Failure to meet the historical debt service coverage ratio and the debt-to-capital ratio are events of default under the credit agreement and Collins lease agreements, which, upon a vote by a majority of the lenders, could cause an acceleration of the due date of the obligations of Edison Mission Midwest Holdings and those associated with the Collins lease. Such an acceleration would result in an event of default under the Powerton and Joliet leases. During the 12 months ended December 31, 2003, the historical debt service coverage ratio was 2.06 to 1 and the debt-to-capital ratio was approximately 0.36 to 1.

There are no restrictions on the ability of Midwest Generation to make payments on the outstanding intercompany loans from its affiliate Edison Mission Overseas Co. (which is also a subsidiary of Edison Mission Midwest Holdings) or to make distributions directly to Edison Mission Midwest Holdings.

EME Homer City Generation L.P. (Homer City facilities)

EME Homer City Generation L.P. 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 in the bullet point 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.

During the 12 months ended December 31, 2003, the senior rent service coverage ratio was 4.68 to 1.

Edison Mission Energy Funding Corp. (Big 4 Projects)

EME's subsidiaries, which EME refers to in this context as the guarantors, that hold EME's interests in the Big 4 projects completed a $450 million secured financing in December 1996. Edison Mission Energy Funding Corp., a special purpose Delaware corporation, issued notes ($260 million) and bonds ($190 million), the net proceeds of which were lent to the guarantors in exchange for a note. The guarantors have pledged their cash proceeds from the Big 4 projects to Edison Mission Energy Funding as collateral for the note. All distributions receivable by the guarantors from the Big 4 projects are deposited into trust accounts from which debt service payments are made on the obligations of Edison Mission Energy Funding and from which distributions may be made to EME if the guarantors and Edison Mission Energy Funding are in compliance with the terms of the covenants in their financing documents, including the following requirements measured on the date of distribution:

- The debt service coverage ratio for the preceding four fiscal quarters is at least 1.25 to 1.

- The debt service coverage ratio projected for the succeeding four fiscal quarters is at least 1.25 to 1.

The debt service coverage ratio is determined primarily based upon the amount of distributions received by the guarantors from the Big 4 projects during the relevant quarter divided by the debt service (principal and interest) on Edison Mission Energy Funding's notes and bonds paid or due in the relevant quarter. During the 12 months ended December 31, 2003, the debt service coverage ratio was 2.16 to 1. Although the credit ratings of Edison Mission Energy Funding's notes and bonds are below investment grade, this has no effect on the ability of the guarantors to make distributions to EME.

Mission Energy Holdings International

Mission Energy Holdings International owns substantially all of EME's international operations through its subsidiary, MEC International B.V., as more fully described in "—Key Financing Developments."

In order to make a distribution, Mission Energy Holdings International must be in compliance with the covenants specified in the credit agreement, including the following:

- Maintenance of a specified interest coverage ratio. For more information about the interest coverage ratio, see "—Financial Ratios—Mission Energy Holdings International Interest Coverage Ratio."

- Ownership by Edison International, directly or indirectly, of at least 80% of Mission Energy Holdings International.

When measured for the twelve-month period ended December 31, 2003, Mission Energy Holdings International interest coverage ratio was 2.75 to 1.

The following subsidiaries of EME have guaranteed the obligations of Mission Energy Holdings International under its secured credit agreement:

- Midwest Generation EME – a direct subsidiary of EME and an indirect parent of Midwest Generation, the entity that owns the Illinois plants.

- Edison Mission Finance – a direct subsidiary of Edison Mission Holdings and the holder of intercompany receivables due from EME Homer City.

- Mission Del Cielo – a direct subsidiary of EME and an indirect parent of Sunrise Power Company, LLC, the entity that owns the Sunrise project.

- Viejo Energy Company, Anacapa Energy Company, Del Mar Energy Company and Silverado Energy Company – each is a direct subsidiary of EME and a general partner in a partnership that owns each of the Westside projects.

Distributions may be made by any of these entities so long as, neither a default nor event of default exists under the Mission Energy Holdings International secured credit agreement.

First Hydro Holdings

A subsidiary of First Hydro Holdings, First Hydro Finance plc, has issued £400 million of Guaranteed Secured Bonds due in 2021. In order to make a distribution, First Hydro Finance must be in compliance with the covenants specified in its bond indenture, including the following interest coverage ratio:

- As determined on June 30 and December 31 of each year, the ratio of net revenue (which is generally the consolidated profit of First Hydro Holdings and its subsidiaries before tax) to interest payable on the Guaranteed Secured Bonds for the prior twelve-month period (taken as a whole) must be greater than 1.2 to 1.

First Hydro Holdings' interest coverage ratio must also exceed a minimum default threshold included in the Guaranteed Secured Bonds. When measured for the twelve-month period ended December 31, 2003, First Hydro Holdings' interest coverage ratio was 1.6 to 1.

In March 2003, the trustee for the First Hydro bonds sent a letter to First Hydro Finance plc on behalf of a group of First Hydro bondholders, requesting First Hydro Finance to engage in a process to determine whether the termination of the pool system in the United Kingdom during 2001 (replaced with the new electricity trading arrangements, referred to as NETA) was materially prejudicial to the interests of the First Hydro bondholders. If this were the case, it could provide the First Hydro bondholders with an early redemption option. First Hydro Finance does not believe that this event was materially prejudicial to the

First Hydro bondholders and has continued to meet all of its debt service obligations and financial covenants under the bond documentation, including required interest coverage ratio. First Hydro Finance is not aware of further actions being pursued by First Hydro bondholders regarding this matter.

Financial Ratios

MEHC's Interest Coverage Ratio

The following details of MEHC's interest coverage ratio are provided as an aid to understanding the components of the computations that are set forth in the indenture governing MEHC's senior secured notes. This information is not intended to measure the financial performance of MEHC and, accordingly, should not be used in lieu of the financial information set forth in MEHC's consolidated financial statements. The terms Funds Flow from Operations, Operating Cash Flow and Interest Expense are as defined in the indenture and are not the same as would be determined in accordance with generally accepted accounting principles.

MEHC's interest coverage ratio is comprised of interest income and expense related to its holding company activities and the consolidated financial information of EME. For a complete discussion of EME's interest coverage ratio and the components included therein, see "—Financial Ratios—EME's Interest Coverage Ratio" below. The following table sets forth MEHC's interest coverage ratio for the years ended December 31, 2003 and 2002:

In millions December 31,	2003	2002
Funds Flow from Operations:		
EME	$ 699	$ 692
Operating cash flow from unrestricted subsidiaries	(2)	(17)
Funds flow from operations of projects sold	(1)	2
MEHC	1	7
	$ 697	$ 684
Interest Expense:		
EME	$ 286	$ 293
EME – affiliate debt	1	2
MEHC interest expense	160	159
Total interest expense	$ 447	$ 454
Interest Coverage Ratio	1.56	1.51

The above interest coverage ratio was determined in accordance with the definitions set forth in the bond indenture governing MEHC's senior secured notes and the credit agreement governing the term loan. The interest coverage ratio prohibits MEHC, EME and its subsidiaries from incurring additional indebtedness, except as specified in the indenture and the financing documents, unless MEHC's interest coverage ratio exceeds 1.75 to 1 for the immediately preceding four fiscal quarters prior to December 31, 2003 and 2.0 to 1 for periods thereafter.

Ability of EME to Pay Dividends

EME's organizational documents and corporate credit facility contain restrictions on its ability to declare or pay dividends or distributions. These restrictions require the unanimous approval of its Board of Directors, including at least one independent director, before it can declare or pay dividends or distributions, unless either of the following is true:

- EME then has investment grade ratings with respect to its senior unsecured long-term debt and receives rating agency confirmation that the dividend or distribution will not result in a downgrade; or

- such dividends and distributions do not exceed $32.5 million in any fiscal quarter and EME then meets an interest coverage ratio of not less than 2.2 to 1 for the immediately preceding four fiscal quarters.

EME's interest coverage ratio for the twelve months ended December 31, 2003 was 2.45 to 1. See further details of EME's interest coverage ratio below. Accordingly, EME is currently permitted to pay dividends of up to $32.5 million per quarter beginning the first quarter of 2004 under the "ring-fencing" provisions of EME's certificate of incorporation and bylaws and corporate credit facility without the approval of the independent director. EME did not pay or declare any dividends to MEHC during 2003.

EME's Interest Coverage Ratio

The following details of EME's interest coverage ratio (defined as Funds Flow from Operations divided by Interest Expense) are provided as an aid to understanding the components of the computations that are set forth in EME's organizational documents. This information is not intended to measure the financial performance of EME and, accordingly, should not be used in lieu of the financial information set forth in EME's consolidated financial statements. The terms Funds Flow from Operations, Operating Cash Flow and Interest Expense are as defined in EME's organizational documents and are not the same as would be determined in accordance with generally accepted accounting principles.

The following table sets forth the major components of the interest coverage ratio for 2003 and 2002:

In millions December 31,	2003	2002
Funds Flow from Operations:		
Operating Cash Flow(1) from Consolidated Operating Projects(2):		
Illinois plants(3)	$ 242	$ 294
Homer City	153	51
First Hydro	(8)	47
Other consolidated operating projects	165	158
Price risk management and energy trading	11	16
Distributions from unconsolidated Big 4 projects(4)	98	137
Distributions from other unconsolidated operating projects	178	120
Interest income	4	8
Operating expenses	(144)	(139)
Total funds flow from operations	$ 699	$ 692
Interest Expense:		
From obligations to unrelated third parties	$ 172	$ 178
From notes payable to Midwest Generation	113	115
Total interest expense	$ 285	$ 293
Interest Coverage Ratio	2.45	2.36

(1) Operating cash flow is defined as revenue less operating expenses, foreign taxes paid and project debt service. Operating cash flow does not include capital expenditures or the difference between cash payments under EME's long-term leases and lease expenses recorded in EME's income statement. EME expects its cash payments under its long-term power plant leases to be higher than its lease expense through 2014.

(2) Consolidated operating projects are entities of which EME owns more than a 50% interest and, thus, include the operating results and cash flows in its consolidated financial statements. Unconsolidated operating projects are entities of which EME owns 50% or less and which EME accounts for on the equity method.

(3) Distribution to EME of funds flow from operations of the Illinois plants is currently restricted. See "—EME's Credit Ratings—Credit Ratings of Edison Mission Midwest Holdings."

(4) The Big 4 projects are comprised of investments in the Kern River project, Midway-Sunset project, Sycamore project and Watson project.

The major factors affecting funds flow from operations during 2003 as compared to 2002, were:

- lower earnings at the Illinois plants primarily due to lower capacity revenue from the reduction in megawatts contracted under the power-purchase agreements;
- repayment of $29 million debt service reserve loan at First Hydro;
- lower distributions from the Big 4 projects (in March 2002, SCE paid the Big 4 projects their past due accounts receivable that accrued during the California energy crisis);
- higher revenue at Homer City due to increased generation and higher energy prices; and
- initial partner distributions from the Sunrise and ISAB Energy projects.

Interest expense decreased by $8 million for the twelve months ended December 31, 2003, compared to the year ended December 31, 2002 due to a lower average debt balance.

The above interest coverage ratio is not determined in accordance with generally accepted accounting principles as reflected in Edison International's Consolidated Statements of Cash Flows. Accordingly, this ratio should not be considered in isolation or as a substitute for cash flows from operating activities or cash flow statement data set forth in Edison International's Consolidated Statement of Cash Flows. This ratio does not measure the liquidity or ability of EME's subsidiaries to meet their debt service obligations. Furthermore, this ratio is not necessarily comparable to other similarly titled captions of other companies due to differences in methods of calculations.

EME Recourse Debt to Recourse Capital Ratio

Under the credit agreement governing its credit facility, EME has agreed to maintain a recourse debt to recourse capital ratio as shown in the table below.

Financial Ratio	Covenant	Actual at December 31, 2003	Description
Recourse Debt to Recourse Capital Ratio	Less than or equal to 67.5%	59.8%	Ratio of (a) senior recourse debt to (b) sum of (i) adjusted shareholder's equity as defined in the credit agreement, *plus* (ii) senior recourse debt

The recourse debt to recourse capital ratio of EME at December 31, 2003 and 2002 was calculated as follows:

In millions December 31,	2003	2002
Recourse Debt(1)		
Corporate Credit Facilities	$ —	$ 140
Senior Notes	1,600	1,600
Guarantee of termination value of Powerton/Joliet operating leases	1,470	1,452
Coal and Capex Facility	29	182
Other	—	30
Total Recourse Debt to EME	$ 3,099	$ 3,404
Adjusted Shareholder's Equity(2)	$ 2,085	$ 2,066
Recourse Capital(3)	$ 5,184	$ 5,470
Recourse Debt to Recourse Capital Ratio	59.8%	62.2%

(1) Recourse debt means senior direct obligations of EME or obligations related to indebtedness or rental expenses of one of its subsidiaries for which EME has provided a guarantee.

(2) Adjusted shareholder's equity is defined as the sum of total shareholder's equity and equity preferred securities, less changes in accumulated other comprehensive gain or loss after December 31, 1999.

(3) Recourse capital is defined as the sum of adjusted shareholder's equity and recourse debt.

EME's indirect subsidiary, Midwest Generation, reported in its second quarter report on Form 10-Q an asset impairment charge of $475 million, after tax, related to the 2,698 MW gas-fired Collins Station. The impairment charge resulted from a write-down of the book value of capitalized assets related to the Collins Station from $858 million to an estimated fair market value of $78 million. The impairment charge by Midwest Generation is not reflected in the operating results of EME because the lease related to the Collins Station is treated in EME's financial statements as an operating lease and not as an asset and, therefore, is not subject to impairment for accounting purposes. See "—Key Financing Developments—EME's Subsidiary Financing Plans—Agreement in Principle to Terminate the Collins Station Lease" for further discussion of the plan to replace EME's corporate credit facility with a new secured credit facility.

Mission Energy Holdings International Interest Coverage Ratio

Under the credit agreement governing its term loan (see "—Dividend Restrictions in Major Financings—Mission Energy Holdings International"), Mission Energy Holdings International has agreed to a minimum interest coverage ratio of 1.30 to 1 beginning March 2004 for the trailing twelve month period.

The following table sets forth the major components of the interest coverage ratio for the twelve months ended December 31, 2003 on a pro forma basis assuming the term loan had been in existence at the beginning of 2003:

	2003		
In millions	Actual	Pro Forma Adjustment[2]	Pro Forma
Funds Flow from Operations			
Historical distributions from international projects[1]	$ 158	$ —	$ 158
Other fees and cash payments considered distributions under the term loan	20	—	20
Administrative and general expenses	(2)	—	(2)
Total Flow of Funds from Operations	$ 176	$ —	$ 176
Term Loan Interest Expense	$ 4	$ 60	$ 64
Interest Coverage Ratio			2.75

(1) See "—EME's Liquidity as a Holding Company—Historical Distributions Received By EME."

(2) The pro forma adjustment assumes the $800 million loan was outstanding at the beginning of 2003. Pro forma interest expense was calculated using the interest rate floor of 7% plus amortization of deferred financing costs.

The above details of Mission Energy Holdings International's interest coverage ratio are provided as an aid to understanding the components of the computations that are set forth in the term loan credit agreement. The terms Funds Flow from Operations and Interest Expense are as defined in the term loan and are not the same as would be determined in accordance with generally accepted accounting principles.

Summarized combined financial information (unaudited) of Mission Energy Holdings International, Inc. and its Subsidiaries and Edison Mission Project Co. is set forth below:

December 31,	2003	2002	2001
Revenue	$1,526	$1,148	$ 835
Expenses	1,410	1,112	2,003
Net income (loss)	$ 116	$ 36	$(1,168)

December 31,	2003	2002
Current assets	$ 621	$ 473
Noncurrent assets	6,723	5,260
Total assets	$7,344	$5,733
Current liabilities	$ 580	$ 470
Noncurrent liabilities	4,994	3,154
Minority interest	746	652
Preferred security	—	131
Equity	1,024	1,326
Total liabilities and equity	$7,344	$5,733

The majority of noncurrent liabilities are comprised of project financing arrangements that are nonrecourse to EME.

MEHC AND EME: MARKET RISK EXPOSURES

EME's primary market risk exposures are associated with the sale of electricity from and the procurement of fuel for its uncontracted generating plants. These market risks arise from fluctuations in electricity and fuel prices, emission allowances, transmission rights, interest rates and foreign currency exchange rates. EME manages these risks in part by using derivative financial instruments in accordance with established policies and procedures. See "MEHC and EME: Management Overview," "MEHC and EME: Liquidity—EME's Credit Ratings" and "Critical Accounting Policies" for a discussion of market developments and their impact on EME's credit and the credit of its counterparties.

Commodity Price Risk

EME's merchant power plants and energy trading activities expose EME to commodity price risks. Commodity price risks are actively monitored to ensure compliance with EME's risk management policies. Policies are in place which define risk tolerances for each EME regional business unit. Procedures exist which allow for monitoring of all commitments and positions with regular reviews by a risk management committee. In order to provide more predictable earnings and cash flow, EME may hedge a portion of the electric output of its merchant plants, the output of which is not committed to be sold under long-term contracts. When appropriate, EME manages the spread between electric prices and fuel prices, and uses forward contracts, swaps, futures, or options contracts to achieve those objectives. There is no assurance that contracts to hedge changes in market prices will be effective.

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

- prevailing market prices for fuel oil, coal and natural gas and associated transportation costs;
- 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;
- transmission congestion in and to each market area;
- the market structure rules to be established for each market area;
- the cost of emission credits or allowances;
- the availability, reliability and operation of nuclear generating plants, where applicable, and the extended operation of nuclear generating plants beyond their presently expected dates of decommissioning;
- weather conditions prevailing in surrounding areas from time to time; and
- the rate of electricity usage as a result of factors such as regional economic conditions and the implementation of conservation programs.

EME performs a "value at risk" analysis in its daily business to measure, monitor and control its overall market risk exposure in respect of its Illinois plants, its Homer City facilities, and its trading positions. The use of value at risk allows management to aggregate overall commodity risk, compare risk on a consistent basis and identify the risk factors. Value at risk measures the possible loss over a given time interval, under normal market conditions, at a given confidence level. Given the inherent limitations of

value at risk and relying on a single risk measurement tool, EME supplements this approach with the use of stress testing and worst-case scenario analysis for key risk factors, as well as stop loss limits and counterparty credit exposure limits. Despite this, there can be no assurance that all risks have been accurately identified, measured and/or mitigated.

Electric power generated at EME's domestic merchant plants is generally sold under bilateral arrangements with utilities and power marketers under short-term transactions with terms of two years or less or, in the case of the Homer City facilities, to the PJM and/or the New York Independent System Operator (NYISO). As discussed further below, beginning in 2003, EME has been selling a significant portion of the power generated from its Illinois plants into wholesale power markets.

Illinois Plants

Energy power generated at the Illinois plants has historically been sold under three power-purchase agreements between EME's wholly owned subsidiary, Midwest Generation, and Exelon Generation Company, in which Exelon Generation purchases capacity and has the right to purchase energy generated by the Illinois plants. The power-purchase agreements, which began on December 15, 1999 and expire in December 2004, provide for capacity and energy payments. Exelon Generation is obligated to make capacity payments for the plants under contract and energy payments for the energy produced by these plants and taken by Exelon Generation. The capacity payments provide the Illinois plants revenue for fixed charges, and the energy payments compensate the Illinois plants for all, or a portion of, variable costs of production.

Approximately 65% of the energy and capacity sales from the Illinois plants in 2003 were to Exelon Generation under the power-purchase agreements. As a result of notices given in 2003, Midwest Generation's reliance on sales into the wholesale market will increase in 2004 from 2003. As discussed in detail below, 3,859 MW of Midwest Generation's generating capacity remains subject to power-purchase agreements with Exelon Generation in 2004. 2004 is the final contract year under these power-purchase agreements.

In June 2003, Exelon Generation exercised its option to contract 687 MW of capacity and the associated energy output (out of a possible total of 1,265 MW subject to option) during 2004 from Midwest Generation's coal-fired units in accordance with the terms of the existing power-purchase agreement related to Midwest Generation's coal-fired generation units. As a result, 578 MW of capacity at the Crawford Unit 7, Waukegan Unit 6 and Will County Unit 3 is no longer subject to the power-purchase agreement beginning January 1, 2004. For 2004, Exelon Generation will have 2,383 MW of capacity related to its coal-fired generation units under contract with Midwest Generation.

In October 2003, Exelon Generation exercised its option to retain under a power-purchase agreement for calendar year 2004 the 1,084 MW of capacity and energy from Midwest Generation's Collins Station. Exelon Generation also exercised its option to release from a related power-purchase agreement 302 MW of capacity and energy (out of a possible total of 694 MW subject to the option) from Midwest Generation's natural gas and oil-fired peaking units, thereby retaining under that contract 392 MW of the capacity and energy of such units for calendar year 2004.

The energy and capacity from any units which are not subject to one of the power-purchase agreements with Exelon Generation will be sold under terms, including price and quantity, negotiated by Edison Mission Marketing & Trading with customers through a combination of bilateral agreements, forward energy sales and spot market sales. These arrangements generally have a term of two years or less. Thus, EME is subject to market risks related to the price of energy and capacity described above. EME expects that capacity prices for merchant energy sales will, in the near term, be negligible in comparison to those Midwest Generation currently receives under its existing agreements with Exelon Generation (the

possibility of minimal revenue is due to the current oversupply conditions in this marketplace). EME further expects that the lower revenue resulting from this difference will be offset in part by energy prices, which EME believes will, in the near term, be higher for merchant energy sales than those Midwest Generation currently receives under its existing agreements, as indicated below in the table of forward-looking prices. EME intends to manage this price risk, in part, by accessing both the wholesale customer and over-the-counter markets described below as well as using derivative financial instruments in accordance with established policies and procedures.

During 2004, the primary markets available to Midwest Generation for wholesale sales of electricity from the Illinois plants are expected to be direct "wholesale customers" and broker-arranged "over-the-counter customers." The most liquid over-the-counter markets in the Midwest region are sales into the control area of Cinergy, referred to as "Into Cinergy," and, to a lesser extent, sales into the control areas of ComEd and AEP, referred to as "Into ComEd" and "Into AEP," respectively. "Into Cinergy," "Into ComEd" and "Into AEP" are bilateral markets for the sale or purchase of electrical energy for future delivery. Performance of transactions in these markets is subject to contracts that generally provide for liquidated damages supported by a variety of credit requirements, which may include independent credit assessment, parent company guarantees, letters of credit, and cash margining arrangements.

The following table depicts the historical average market prices for energy per megawatt-hour "Into ComEd" and "Into Cinergy" for 2003. Due to geographic proximity, "Into ComEd" has been the primary market for Midwest Generation. Market prices are included for "Into Cinergy" for illustrative purposes.

	2003 Into ComEd*			2003 Into Cinergy*		
Historical Energy Prices	On-Peak(1)	Off-Peak(1)	24-Hr	On-Peak(1)	Off-Peak(1)	24-Hr
January	$ 42.62	$ 20.77	$ 30.81	$ 44.38	$ 21.46	$ 32.00
February	54.43	23.13	37.81	58.09	24.00	39.99
March	47.96	22.35	33.92	51.68	24.34	36.69
April	39.12	15.05	26.67	41.12	15.96	28.11
May	29.59	10.80	19.57	28.89	10.68	19.18
June	30.27	8.17	19.22	28.41	8.31	18.36
July	41.63	12.81	27.07	39.15	11.72	25.29
August	48.75	13.84	29.61	48.80	13.53	29.46
September	27.44	9.85	17.67	28.07	10.36	18.23
October	24.47	12.01	18.17	24.95	13.51	19.17
November	24.78	14.32	18.51	23.66	14.61	18.23
December	34.72	12.49	22.56	34.71	14.73	23.73
Yearly Average	$ 37.15	$ 14.63	$ 25.13	$ 37.66	$ 15.27	$ 25.70

(1) On-peak refers to the hours of the day between 6:00 a.m. and 10:00 p.m. Monday through Friday, excluding North American Electric Reliability Council (NERC) holidays. All other hours of the week are referred to as off-peak.

* Source: Energy prices were determined by obtaining broker quotes and other public price sources, for both "Into ComEd" and "Into Cinergy" delivery points.

The following table sets forth the forward month-end market prices for energy per megawatt-hour for the calendar year 2004 and calendar year 2005 "strips," which are defined as energy purchases for the entire calendar year, as quoted for sales "Into ComEd" and "Into Cinergy" during 2003. These forward prices will continue to fluctuate as a result of a number of factors, including gas prices, electricity demand, which is also affected by economic growth, and the amount of existing and planned power plant capacity.

The actual spot prices for electricity delivered into these markets may vary materially from the forward market prices.

Forward Energy Prices	Into ComEd*					
	2004			2005		
Date	On-Peak(1)	Off-Peak(1)	24-Hr	On-Peak(1)	Off-Peak(1)	24-Hr
January 31, 2003	$45.50	$ 18.75	$30.83	$40.75	$ 19.50	$29.10
February 28, 2003	41.15	18.25	28.78	39.75	19.00	28.88
March 31, 2003	37.00	16.75	26.76	38.75	17.75	28.14
April 30, 2003	34.39	16.25	25.12	36.75	17.25	26.35
May 31, 2003	31.09	15.75	22.35	33.50	16.75	24.31
June 30, 2003	34.17	17.25	25.52	36.00	18.25	26.93
July 31, 2003	44.72	20.00	31.16	45.50	21.00	31.54
August 30, 2003	43.72	19.00	30.70	44.50	20.00	32.12
September 30, 2003	31.33	15.75	23.02	31.00	16.75	23.40
October 31, 2003	27.17	14.75	20.36	28.00	15.75	21.28
November 27, 2003	28.17	14.75	21.01	29.00	15.75	21.93
December 31, 2003	30.17	15.25	22.63	31.00	16.25	22.91

Forward Energy Prices	Into Cinergy*					
	2004			2005		
Date	On-Peak(1)	Off-Peak(1)	24-Hr	On-Peak(1)	Off-Peak(1)	24-Hr
January 31, 2003	$45.00	$ 20.00	$31.29	$41.57	$ 21.38	$30.50
February 28, 2003	41.53	19.70	29.73	40.56	20.88	30.25
March 31, 2003	38.86	18.57	28.60	38.95	19.63	29.18
April 30, 2003	36.80	18.07	27.22	36.95	19.13	27.44
May 31, 2003	32.95	17.98	24.42	34.18	18.43	25.54
June 30, 2003	36.68	18.98	27.63	37.74	19.93	28.64
July 31, 2003	46.15	21.88	32.84	47.34	22.88	33.40
August 30, 2003	45.15	20.88	32.36	46.34	21.88	33.98
September 30, 2003	33.25	17.36	24.77	33.63	18.44	25.52
October 31, 2003	29.62	17.08	22.74	30.12	17.68	23.29
November 27, 2003	30.62	17.08	23.40	31.11	17.68	23.95
December 31, 2003	32.62	17.58	25.02	33.11	18.18	24.92

(1) On-peak refers to the hours of the day between 6:00 a.m. and 10:00 p.m. Monday through Friday, excluding NERC holidays. All other hours of the week are referred to as off-peak.

* Source: Energy prices were determined by obtaining broker quotes and other public price sources, for both "Into ComEd" and "Into Cinergy" delivery points.

Midwest Generation intends to hedge a portion of its merchant portfolio risk through Edison Mission Marketing & Trading. To the extent it does not do so, the unhedged portion will be subject to the risks and benefits of spot market price movements. The extent to which Midwest Generation will hedge its market price risk through forward over-the-counter sales depends on several factors. First, Midwest Generation will evaluate over-the-counter market prices to determine whether sales at forward market prices are sufficiently attractive compared to assuming the risk associated with spot market sales. Second, Midwest Generation's ability to enter into hedging transactions will depend upon its and Edison Mission Marketing & Trading's credit capacity and upon the over-the-counter forward sales markets having

sufficient liquidity to enable Midwest Generation to identify counterparties who are able and willing to enter into hedging transactions with it. Due to factors beyond Midwest Generation's control, market liquidity has decreased significantly since the beginning of 2002 and a number of formerly significant trading parties have completely withdrawn from the market or substantially reduced their trading activities, resulting in far fewer creditworthy participants in these electricity markets. See "—Credit Risk," below.

In addition to the prevailing market prices, Midwest Generation's ability to derive profits from the sale of electricity from the released units will be affected by the cost of production, including costs incurred to comply with environmental regulations. The costs of production of the released units vary and, accordingly, depending on market conditions, the amount of generation that will be sold from the released units is expected to vary from unit to unit. In this regard, Midwest Generation suspended operations of Will County Units 1 and 2 and Collins Station Units 4 and 5 at the end of 2002 pending improvement in market conditions.

Under PJM's proposed revisions to the PJM Tariff, the integration of ComEd into PJM could result in market power mitigation measures being imposed on future power sales by Midwest Generation in the NICA energy and capacity markets. In addition, power produced by Midwest Generation not under contract with Exelon Generation is sold using transmission obtained from ComEd under its open-access tariff filed with the FERC, and the application of the PJM Tariff to ComEd's transmission system could also affect the rates, terms and conditions of transmission service received by Midwest Generation. EME and Midwest Generation have contested the appropriateness of ComEd joining PJM on an "islanded" basis and the imposition of market power mitigation measures proposed by PJM for the NICA energy and capacity markets. EME is unable to predict the outcome of these efforts, the effect of integration of ComEd into PJM on an "islanded" basis, the effect of integration of AEP into PJM, or any final integration configuration for PJM on the markets into which Midwest Generation sells its power.

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

Homer City Facilities

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

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

	24-Hour PJM Historical Energy Prices*		
	2003	2002	2001
January	$ 36.56	$ 20.52	$ 36.66
February	46.13	20.62	29.53
March	46.85	24.27	35.05
April	35.35	25.68	34.58
May	32.29	21.98	28.64
June	27.26	24.98	26.61
July	36.55	30.01	30.21
August	39.27	30.40	43.99
September	28.71	29.00	22.44
October	26.96	27.64	21.95
November	29.17	25.18	19.58
December	35.89	27.33	19.66
Yearly Average	$ 35.08	$ 25.63	$ 29.07

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

As shown on the above table, the average historical market prices at the Homer City busbar (delivery point) during 2003 were higher than the average historical market prices during 2002, although in September and October of each year the power prices were similar. Forward market prices in PJM fluctuate as a result of a number of factors, including natural gas prices, transmission congestion, changes in market rules, electricity demand which is affected by weather and economic growth, and the amount of existing and planned power plant capacity. The actual spot prices for electricity delivered into these markets may vary materially from the forward market prices.

Sales made in the real-time or day-ahead market receive the actual spot prices at the Homer City busbar. In order to mitigate price risk from changes in spot prices at the Homer City busbar, EME may enter into forward contracts with counterparties for forecasted generation in future periods. Currently, there is not a liquid market for entering into forward contracts at the Homer City busbar. A liquid market does exist for delivery to a collection of delivery points known as PJM West Hub, which EME's price risk management activities use to enter into forward contracts. EME's revenue with respect to such forward contracts include:

- sales of actual generation in the amounts covered by such forward contracts with reference to PJM spot prices at the Homer City busbar, plus,

- sales to third parties under such forward contracts at designated delivery points (generally the PJM West Hub) less the cost of purchasing power at spot prices at the same designated delivery points to fulfill obligations under such forward contracts.

Under the PJM market design, locational marginal pricing (sometimes referred to as LMP), which establishes hourly prices at specific locations throughout PJM by considering factors including generator bids, load requirements, transmission congestion and losses, has the effect of raising prices at those delivery points affected by transmission congestion. During the past 12 months, an increase in transmission congestion at delivery points east of the Homer City facilities has resulted in prices at the PJM West Hub (which includes delivery points east of the Homer City facilities) being higher than those

at the Homer City busbar. Thus, while forward prices at PJM West Hub have historically been higher than the prices at the Homer City busbar by less than 5%, increased congestion during the last 12 months at delivery points east of the Homer City facilities has resulted in prices at PJM West Hub being on average 6% higher than those at the Homer City busbar.

By entering into forward contracts using the PJM West Hub as the delivery point, EME is exposed to "basis risk," which occurs when forward contracts are executed on a different basis (in this case PJM West Hub) than the actual point of delivery (Homer City busbar). In order to mitigate basis risk resulting from forward contracts using PJM West Hub as the delivery point, EME has participated in purchasing fixed transmission rights in PJM, and may continue to do so in the future. A fixed transmission right provides the holder with a financial instrument to receive actual spot prices at one point of delivery and pay prices at another point of delivery that are pegged to prices at the first point of delivery, plus or minus a fixed amount. Accordingly, EME's price risk management activities include using fixed transmission rights alone or in combination with forward contracts to manage the risks associated with changes in prices within the PJM market.

The following table sets forth the forward month-end market prices per megawatt-hour for the calendar 2004 and 2005 "strips," which are defined as energy purchases for the entire calendar year, as quoted for sales into the PJM West Hub during 2003:

	24-Hour PJM West Forward Energy Prices*	
	2004	2005
January 31, 2003	$ 43.03	$ 37.75
February 28, 2003	42.88	38.18
March 31, 2003	39.57	33.88
April 30, 2003	34.45	32.85
May 31, 2003	30.20	30.60
June 30, 2003	34.23	33.45
July 31, 2003	41.67	39.77
August 30, 2003	42.31	41.61
September 30, 2003	30.20	30.62
October 31, 2003	29.02	28.51
November 27, 2003	29.49	28.74
December 31, 2003	30.18	28.51

* Energy prices were determined by obtaining broker quotes and other public sources for the PJM West Hub delivery point. Forward prices at PJM West are generally higher than the prices at the Homer City busbar.

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

United Kingdom

The First Hydro plant sells electrical energy and capacity through bilateral contracts of varying terms in the England and Wales wholesale electricity market.

The electricity trading arrangements introduced in March 2001 provide, among other things, for the establishment of a range of voluntary short-term power exchanges and brokered markets operating from a year or more in advance to 1 hour prior to the delivery or receipt of power. In the final hour after the notification of all contracts, the system operator can accept bids and offers in the Balancing Mechanism to balance generation and demand and resolve any transmission constraints. There is a mandatory settlement process for recovering imbalances between contracted and metered volumes with strong incentives for being in balance, and a Balancing and Settlement Code Panel to oversee governance of the Balancing Mechanism. The system operator can also purchase system reserve and response services to maintain the quality of the electrical supply directly from generators (generally referred to as "ancillary services"). Ancillary services contracts typically run for up to a year and can consist of both fixed amounts and variable amounts represented by prices for services that are only paid for when actually called upon by the grid operator. A key feature of the trading arrangements is the requirement for firm physical delivery, which means that a generator must deliver, and a consumer must take delivery of, its net contracted positions or pay for any energy imbalance at the imbalance prices calculated by the system operator based on the prices of bids and offers accepted in the Balancing Mechanism. This provides an incentive for parties to contract in advance and for the development of forwards and futures markets. Under these arrangements, there has been an increased emphasis on credit quality, including the need for parent company guarantees or letters of credit for companies below investment grade.

The wholesale price of electricity has decreased significantly in recent years. The reduction has been driven principally by surplus generating capacity and increased competition. During 2003, prices were more volatile. There was further downward pressure on wholesale prices in the first part of the year followed by some recovery during the summer in prices and in the peak/off peak differentials for the upcoming winter period. That recovery tailed off towards the end of the year with a considerable narrowing in the peak/off peak differentials. Compliance with First Hydro's bond financing documents is subject to market conditions for electric energy and ancillary services, which are beyond First Hydro's control.

Australia

The Loy Yang B plant and the Valley Power Peaker project sell electrical energy through a centralized electricity pool, which provides for a system of generator bidding, central dispatch and a settlements system based on a clearing market for each half-hour of every day. The National Electricity Market Management Company, operator and administrator of the pool, determines a spot price each half-hour. To mitigate exposure to price volatility of the electricity traded into the pool, the Loy Yang B plant and the Valley Power Peaker project have entered into a number of financial hedges. The State Hedge agreement with the State Electricity Commission of Victoria is a long-term contractual arrangement based upon a fixed price commencing May 8, 1997 and terminating October 31, 2016. The State Government of Victoria, Australia guarantees the State Electricity Commission of Victoria's obligations under the State Hedge. From January 2003 to July 2014, approximately 77% of the Loy Yang B plant output sold is hedged under the State Hedge. From August 2014 to October 2016, approximately 56% of the Loy Yang B plant output sold is hedged under the State Hedge. Additionally, the Loy Yang B plant and the Valley Power Peaker project have entered into a number of derivative contracts to mitigate further against price volatility inherent in the electricity pool. These contracts consist of fixed forward electricity contracts and/or cap contracts that expire on various dates through December 31, 2006.

New Zealand

Contact Energy generates about 30% of New Zealand's electricity and is the largest retailer of natural gas and electricity in New Zealand. A substantial portion of Contact Energy's generation output is matched with the demand of its retail electricity customers or sold through forward contracts with other wholesale electricity counterparties. The forward contracts and/or option contracts have varying terms that expire on

various dates through June 30, 2010, although the majority of the forward contracts are short term (less than two years).

The New Zealand government released a government policy statement in December 2001, which called for the industry to rationalize the three existing industry codes, form a single governance structure and address transmission investment and pricing issues. The industry was unable to agree on new rules to facilitate the government policy statement.

Subsequently, in May 2003, the New Zealand government announced that it would establish a new governance body to be known as the Electricity Commission along with a set of rules to govern the market. The Electricity Governance Regulations and Rules were finalized in 2003. The Regulations came into force on January 16, 2004, and the Rules came into force during February and March of 2004.

During the winter of 2003, wholesale electricity prices increased significantly in response to lower hydro inflows, higher demand and anticipated restrictions on the availability of thermal fuel. The New Zealand government responded by calling for nationwide energy savings in the order of 10%. Recent rains and anticipated snowmelt have largely improved the earlier conditions with wholesale electricity prices returning to more normal levels. The national energy savings program ended in July 2003.

However, there are ongoing concerns that new investment in generation has not been forthcoming and that there is a significant risk that similar events may arise in subsequent years. As a consequence the New Zealand government announced that it will take the following steps:

- the Electricity Commission will be given responsibility for managing dry year reserve, expected to be through the procurement of reserve capacity; and
- the Electricity Commission will be given additional reserve powers ranging from information disclosure to imposing hedge obligations on major users and generators.

Submissions have been made in respect of the policy, which are currently being considered by the New Zealand government. Final details of the policy were released in September 2003, and it is expected that legislation will be passed in 2004.

The New Zealand government announced in July 2003 that it would purchase a new 155 MW power plant before winter 2004 to increase electricity security. The plant is to be situated at Whirinaki, Hawkes Bay. The Electricity Commission will be required to include this plant in its portfolio of reserve energy. The Whirinaki plant will be located on a site leased to the government from Contact Energy and will also be operated under contract by Contact Energy.

Credit Risk

In conducting EME's price risk management and trading activities, EME contracts with a number of utilities, energy companies and financial institutions, collectively referred to as counterparties. Due to factors beyond EME's control, a number of formerly significant trading parties have completely withdrawn from the market or substantially reduced their trading activities since the beginning of 2002, thereby potentially increasing exposure to the remaining counterparties. The reduction in the credit quality of traditional trading parties increases EME's credit risk. In addition, the decrease in market liquidity may require EME to rely more heavily on wholesale electricity sales to wholesale customer markets which may also increase EME's credit risk. In the event a counterparty were to default on its trade obligation, EME would be exposed to the risk of possible loss associated with reselling the contracted product at a lower price if the nonperforming counterparty were unable to pay the resulting

liquidated damages owed to EME. Further, EME would be exposed to the risk of nonpayment of accounts receivable accrued for products delivered prior to the time such counterparty defaulted.

To manage credit risk, EME looks at the risk of a potential default by 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, to the extent possible, credit risk. To mitigate counterparty risk, 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.

EME measures credit risk exposure from counterparties of its merchant energy activities by the sum of: (i) 60 days of accounts receivable, (ii) current fair value of open positions, and (iii) a credit value at risk. EME's subsidiaries enter into master agreements and other arrangements in conducting price risk management and trading activities which typically provide for a right of setoff in the event of bankruptcy or default by the counterparty. Accordingly, EME's credit risk exposure from counterparties is based on net exposure under these agreements. At December 31, 2003, the credit ratings of EME's counterparties were as follows:

In millions December 31,	2003
S&P Credit Rating	
A or higher	$ 101
A-	26
BBB+	82
BBB	57
BBB-	14
Below investment grade	—
Total	$ 280

Exelon Generation accounted for 22%, 40% and 42% of nonutility power generation revenue in 2003, 2002 and 2001, respectively. EME expects the percentage to be less in 2004 because a smaller number of plants will be subject to contracts with Exelon Generation. See "—Commodity Price Risk—Illinois Plants." Any failure of Exelon Generation to make payments under the power-purchase agreements could adversely affect EME's results of operations and financial condition.

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

Interest Rate Risk

MEHC has mitigated the risk of interest rate fluctuations associated with the $385 million term loan due 2006 by arranging for variable rate financing with interest rate swaps. Swaps covering interest accrued from January 2, 2002 to January 2, 2003 expired on January 2, 2003. Subsequently, MEHC entered into swaps that cover interest accrued from January 2, 2003 to July 2, 2004 and April 2, 2003 to July 2, 2004. A 10% fluctuation in market interest rates at December 31, 2003 would change the fair value of MEHC's interest rate swaps by approximately $237 thousand.

The fair market value of MEHC's (stand alone) total long-term obligations was $1.2 billion at December 31, 2003, compared to the carrying value of $1.2 billion. A 10% increase in market interest rates at December 31, 2003 would result in a decrease in the fair value of total long-term obligations by approximately $34 million. A 10% decrease in market interest rates at December 31, 2003 would result in an increase in the fair value of total long-term obligations by approximately $36 million.

Interest rate changes affect the cost of capital needed to operate EME's projects and the lease costs under the Collins Station lease. EME has mitigated the risk of interest rate fluctuations by arranging for fixed rate financing or variable rate financing with interest rate swaps, interest rate options or other hedging mechanisms for a number of its project financings. Interest expense included $60 million, $34 million and $17 million of additional interest expense for the years 2003, 2002 and 2001, respectively, as a result of interest rate hedging mechanisms. EME has entered into several interest rate swap agreements under which the maturity date of the swaps occurs prior to the final maturity of the underlying debt. A 10% increase in market interest rates at December 31, 2003 would result in a $14 million increase in the fair value of EME's interest rate hedge agreements. A 10% decrease in market interest rates at December 31, 2003 would result in a $15 million decrease in the fair value of EME's interest rate hedge agreements. Based on the amount of variable rate long-term debt for which EME has not entered into interest rate hedge agreements and the amount of the Collins lease at December 31, 2003, a 100 basis point change in interest rates at December 31, 2003 would increase or decrease 2004 income before taxes by approximately $23 million.

EME had short-term obligations of $52 million at December 31, 2003, consisting of promissory notes related to Contact Energy. The fair values of these obligations approximated their carrying values at December 31, 2003, and would not have been materially affected by changes in market interest rates. The fair market values of long-term fixed interest rate obligations are subject to interest rate risk. The fair market value of MEHC's total long-term obligations (including current portion) was $7.3 billion at December 31, 2003, compared to the carrying value of $7.4 billion. A 10% increase in market interest rates at December 31, 2003 would result in a decrease in the fair value of total long-term obligations by approximately $159 million. A 10% decrease in market interest rates at December 31, 2003 would result in an increase in the fair value of total long-term obligations by approximately $172 million.

Foreign Exchange Rate Risk

Fluctuations in foreign currency exchange rates can affect, on a United States dollar equivalent basis, the amount of EME's equity contributions to, and distributions from, its international projects. At times, EME has hedged a portion of its current exposure to fluctuations in foreign exchange rates through financial derivatives, offsetting obligations denominated in foreign currencies, and indexing underlying project agreements to United States dollars or other indices reasonably expected to correlate with foreign exchange movements. In addition, EME has used statistical forecasting techniques to help assess foreign exchange risk and the probabilities of various outcomes. EME cannot provide assurances, however, that fluctuations in exchange rates will be fully offset by hedges or that currency movements and the relationship between certain macroeconomic variables will behave in a manner that is consistent with historical or forecasted relationships.

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

During 2003, foreign currencies in Australia, New Zealand and the United Kingdom increased in value compared to the United States dollar by 34%, 25% and 11%, respectively (determined by the change in the exchange rates from December 31, 2002 to December 31, 2003). The increase in value of these currencies was the primary reason for the foreign currency translation gain of $154 million during 2003. A 10% increase in the exchange rates at December 31, 2003 would result in foreign currency translation gains of $329 million. A 10% decrease in the exchange rates at December 31, 2003 would result in foreign currency translation gains of $40 million.

Contact Energy enters into foreign currency forward exchange contracts to hedge identifiable foreign currency commitments associated with transactions in the ordinary course of business. The contracts are primarily in Australian and United States dollars with varying maturities through February 2006. At December 31, 2003, the outstanding notional amount of the contracts totaled $29 million and the fair value of the contracts totaled $(2) million. A 10% decrease in the exchange rates at December 31, 2003 would result in a $2 million increase in the fair value of the contracts.

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

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

Fair Value of Financial Instruments

Non-Trading Derivative Financial Instruments

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

In millions December 31,	2003	2002
Derivatives:		
Interest rate:		
Interest rate swap/cap agreements	$ (34)	$ (56)
Interest rate options	(1)	(2)
Commodity price:		
Electricity	(126)	(100)
Foreign currency forward exchange agreements	(2)	—
Cross currency interest rate swaps	(91)	(2)

In assessing the fair value of EME's non-trading derivative financial instruments, EME uses a variety of methods and assumptions based on the market conditions and associated risks existing at each balance sheet date. The fair value of commodity price contracts takes into account quoted market prices, time value of money, volatility of the underlying commodities and other factors. The fair value of outstanding derivative commodity price contracts that would be expected after a 10% adverse price change at December 31, 2003 is $(143) million. The following table summarizes the maturities, the valuation method and the related fair value of EME's commodity price risk management assets and liabilities (as of December 31, 2003):

In millions	Total Fair Value	Maturity Less than 1 year	Maturity 1 to 3 years	Maturity 4 to 5 years	Maturity Greater than 5 years
Prices actively quoted	$ (3)	$ (4)	$ 1	$ —	$ —
Prices based on models and other valuation methods	(123)	19	8	(13)	(137)
Total	$(126)	$ 15	$ 9	$ (13)	$(137)

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

Energy Trading Derivative Financial Instruments

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

The fair value of the commodity financial instruments related to energy trading activities as of December 31, 2003 and December 31, 2002, are set forth below:

	December 31, 2003		December 31, 2002	
In millions	Assets	Liabilities	Assets	Liabilities
Electricity	$104	$ 11	$109	$ 15
Other	—	1	—	2
Total	$104	$ 12	$109	$ 17

The fair value of trading contracts that would be expected after a 10% adverse price change at December 31, 2003 are shown in the table below:

In millions	Fair Value	Fair Value After 10% Adverse Price Change
Electricity	$ 93	$ 94
Other	(1)	(1)
Total	$ 92	$ 93

The change in the fair value of trading contracts for the year ended December 31, 2003, was as follows:

In millions	Fair Value
Fair value of trading contracts at January 1, 2003	$ 92
Net gains from energy trading activities	40
Amount realized from energy trading activities	(40)
Fair value of trading contracts at December 31, 2003	$ 92

Quoted market prices are used to determine the fair value of the financial instruments related to energy trading activities, except for the power sales agreement with an unaffiliated electric utility that EME's subsidiary purchased and restructured and a long-term power supply agreement with another unaffiliated party. EME's subsidiary recorded these agreements at fair value based upon a discounting of future electricity prices derived from a proprietary model using a discount rate equal to the cost of borrowing the nonrecourse 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, 2003):

In millions	Total Fair Value	Maturity Less than 1 year	Maturity 1 to 3 years	Maturity 4 to 5 years	Maturity Greater than 5 years
Prices actively quoted	$ —	$ —	$ —	$ —	$ —
Prices based on models and other valuation methods	92	(3)	5	9	81
Total	$ 92	$ (3)	$ 5	$ 9	$ 81

EDISON CAPITAL

EDISON CAPITAL: MANAGEMENT OVERVIEW

Edison Capital is a global provider of capital and financial services in energy, affordable housing, and infrastructure projects focusing primarily on investments related to the production and delivery of electricity.

Edison Capital has $2.6 billion invested worldwide in energy and infrastructure projects, including electric generation, transmission and distribution, transportation and telecommunications. These investments are in the form of long-term domestic and cross-border leveraged leases, partnership interests in international infrastructure funds, and domestic companies that operate renewable energy projects including wind power. The leveraged lease investments depend upon the operation of the asset, the lessee's performance of its contract obligations, enforcement of remedies and the sufficiency of collateral in the event of default, and realization of tax benefits. The infrastructure fund investments depend upon the sale on favorable terms of the project assets held by the funds. The domestic wind power investments depend upon wind resources, the operation of the assets, the sale of electricity under long-term power-purchase agreements and realization of energy production tax credits and other tax benefits.

Edison Capital also has $71 million invested in affordable housing projects located throughout the United States. The investments are usually in the form of majority interests in limited partnerships or limited liability companies of which a significant portion has been sold to other parties. The affordable housing investments depend primarily upon realization of low-income housing tax credits.

A significant portion of revenue is derived from lease income. A major component of earnings includes the realization of low-income housing and energy production tax credits and gains or losses realized on sale of project assets by the infrastructure funds. Sources of cash result from lease payments, distributions from sale of project assets by the infrastructure funds and Edison International's ability to utilize tax benefits and credits from Edison Capital's investments.

Edison Capital management is currently concerned about several matters. First, the Internal Revenue Service (IRS) is expected to challenge Edison Capital's tax position in certain types of cross-border, leveraged leases as further described in "Other Developments—Federal Income Taxes." Second, Edison Capital's investments in three aircraft leased to American Airlines may be impacted by economic conditions affecting American Airlines. Third, Edison Capital's receipt of payments under a lease of a domestic electric generation asset may be indirectly impacted by the regulatory and economic conditions affecting the utility purchasing power from that asset. The matters are discussed below.

Edison Capital is currently pursuing new electric infrastructure investments, including renewable energy, after suspending all new investments since 2001 in order to conserve cash in response to the California energy crisis. Edison Capital is also evaluating whether to pursue new affordable housing investments.

EDISON CAPITAL: LIQUIDITY

Since 2001, as a result of the California energy crisis, Edison Capital reduced debt and accumulated cash, which resulted in a significant de-leveraging of Edison Capital. In light of Edison Capital's improved liquidity, Edison Capital made a $225 million dividend payment to Edison International while maintaining a cash and cash equivalent balance of $354 million at December 31, 2003. The improvement in liquidity is primarily from Edison International's utilization of tax benefits that had been delayed in previous years because of the California energy crisis. Edison Capital expects to meet its operating cash needs through cash on hand, tax-allocation payments from the parent company and expected cash flow

from operating activities. To the extent that certain funding conditions are satisfied, Edison Capital has unfunded current and long-term commitments of $68 million for energy and infrastructure investments. In 2004, Edison Capital is evaluating its capital structure, the potential for additional borrowings and potentially making dividend payments to Edison International.

At December 31, 2003, Edison Capital's long-term debt had credit ratings of Ba1 and BB+ from Moody's and Standard & Poor's, respectively.

Edison Capital's Intercompany Tax-Allocation Payments

Edison Capital is included in the consolidated federal and combined state income tax returns of Edison International and is eligible to participate in tax-allocation payments with Edison International and other subsidiaries of Edison International. See "MEHC and EME: Liquidity—EME's Liquidity as a Holding Company—Intercompany Tax-Allocation Payments" for additional information regarding these arrangements. Edison Capital received $141 million in tax-allocation payments from Edison International during 2003. The amount received is net of payments made to Edison International. In the future, Edison Capital may be obligated to make payments under the tax-allocation agreements. (See "Other Developments—Federal Income Taxes" for further discussion of tax-related issues regarding Edison Capital's leveraged leases).

EDISON CAPITAL: MARKET RISK EXPOSURES

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

Interest Rate Risk

Changes in interest rates can have an impact on Edison Capital's results of operations. Edison Capital is exposed to changes in interest rates primarily as a result of its borrowing and investing activities. The nature and amount of Edison Capital's long- and short-term debt can be expected to vary as a result of future business requirements and other factors.

Edison Capital believes that the fair market value of its fixed rate long-term debt is subject to interest rate risk. At December 31, 2003, a 10% increase in market interest rates would have resulted in a $6 million decrease in the fair market value of Edison Capital's long-term debt. A 10% decrease in market interest rates would have resulted in a $7 million increase in the fair market value of Edison Capital's long-term debt.

Foreign Currency Exchange Risk

At December 31, 2003, Edison Capital's outstanding debt included £75 million and the cash equivalents balance included £75 million (both approximately $134 million) which result in self hedging of the outstanding balances with differences in interest rates and payment dates subject to foreign currency exchange fluctuations. A decrease in the cash equivalents balance noted above will increase the risk associated with foreign currency exchange fluctuations.

Credit and Performance Risk

Edison Capital's investments may be affected by the financial condition of other parties, the performance of the asset, economic conditions and other business and legal factors. Edison Capital generally does not control operations or management of the projects 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 the projects.

At December 31, 2003, Edison Capital has $42 million invested for an 8.5% ownership interest in a 1,500 MW gas-fired co-generation power plant leased to Midland Cogeneration Ventures. Midland Cogeneration Ventures sells electricity to Consumers Energy under a long-term power-purchase agreement. The energy and capacity prices paid to Midland Cogeneration Ventures under the power-purchase agreement are based on the avoided cost of a coal plant established by the Michigan Public Services Commission. However, the cost of gas that Midland Cogeneration Ventures must purchase to operate the plant has increased significantly in the last several years.

Consumers Energy is seeking Michigan Public Services Commission's authorization of a resource conservation plan designed to provide natural gas conservation that would revise dispatch procedures applicable to the power purchased under the power-purchase agreement. Edison Capital is currently evaluating the impact that the resource conservation plan might have on Midland Cogeneration Ventures and its ability to make lease payments to Edison Capital. At December 31, 2003, Midland Cogeneration Ventures was current on its lease payments to Edison Capital. Midland Cogeneration Ventures also had lease payment reserves of $299 million at January 31, 2004.

Edison Capital has $63 million invested in three aircraft leased to American Airlines. The independent auditors' opinion on the year-end 2002 financial statements of AMR Corporation, parent company of American Airlines, questions AMR Corporation's ability to continue as a going concern. As disclosed in AMR Corporation's Form 10-Q filing for September 30, 2003, there were some improvements made in 2003, such as concessionary agreements with unions and certain other lessors, and reporting operating income of $165 million for the third quarter of 2003. However, significant uncertainty remains and if American Airlines defaults in making its lease payments, the lenders with a security interest in the aircraft or leases may exercise remedies that could lead to a loss of some or all of Edison Capital's investment in the aircraft plus any accrued interest. The total maximum loss exposure to Edison Capital in 2004 is $46 million. A restructure of the lease could also result in a loss of some or all of the investment. At December 31, 2003, American Airlines was current in its lease payments to Edison Capital.

EDISON INTERNATIONAL (PARENT)

EDISON INTERNATIONAL (PARENT): LIQUIDITY ISSUES

The parent company's liquidity and its ability to pay interest, debt principal, operating expenses and dividends to common shareholders are affected by dividends from subsidiaries, tax-allocation payments under its tax-allocation agreements with its subsidiaries, and access to capital markets or external financings. Edison International is focused on reducing its parent company debt in 2004, which may further impact Edison International's liquidity.

Edison International (parent)'s 2004 cash requirements primarily consist of:

- $618 million of 6-7/8% notes due September 2004. During January and February 2004, Edison International repurchased approximately $46 million of these notes, leaving a remaining balance of $572 million of notes due in September 2004;
- Interest payments on its long-term notes payable related to the quarterly income debt securities of approximately $67 million;
- General operating expenses; and
- Dividends to common shareholders.

Edison International (parent) expects to meet its continuing obligations through cash and cash equivalents on hand and dividends from its subsidiaries. At December 31, 2003, Edison International (parent) had approximately $1.1 billion of cash and cash equivalents on hand.

Beginning in May 2001, Edison International deferred interest payments in accordance with the terms of its outstanding $825 million quarterly income debt securities, due 2029, issued to affiliates (EIX Trust I and II, which are Delaware business trusts). This interest payment deferral caused a corresponding deferral of distributions on quarterly income preferred securities issued by that affiliate. Interest payments may be deferred for up to 20 consecutive quarters. On December 2, 2003, Edison International made aggregate payments of approximately $205 million, which covered repayment of the deferred distributions, with interest, and payment of the distribution due on November 30, 2003. Edison International has resumed quarterly distributions on the quarterly income debt securities, subject to its rights to begin deferring distributions again in the future at its election. As of December 31, 2003, Edison International deconsolidated EIX Trust I and II, and as a result these securities are now included in long-term debt. See "New Accounting Principles" for further discussion.

On October 16, 2003, Edison International received cash dividends of $945 million from SCE and $225 million from Edison Capital. The receipt of dividends from SCE and Edison Capital, as well as the payment of all deferred amounts on the quarterly income debt securities allowed Edison International to declare a common dividend to its shareholders. On December 11, 2003, the Board of Directors of Edison International declared a 20¢ per share common stock dividend. The $65 million dividend payment was made on January 30, 2004.

The CPUC regulates SCE's capital structure by requiring that SCE maintain prescribed percentages of common equity, preferred stock 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 prescribed level. 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. SCE's 2001 CPUC settlement agreement precluded SCE from declaring or paying dividends or other distributions on its

common stock (all of which is held by its parent, Edison International) prior to the date on which SCE had recovered all of its procurement-related obligations, with certain exceptions. SCE fully recovered the PROACT balance during July 2003, and paid a $945 million dividend to Edison International in October 2003 (see further discussion in "SCE: Liquidity Issues"). Other factors at SCE that affect the amount and timing of dividend payments by SCE to Edison International include, among other things, SCE's cash requirements, SCE's access to capital markets, and actions by the CPUC.

MEHC may not pay dividends unless it has an interest coverage ratio of at least 2.0 to 1. At December 31, 2003, its interest coverage ratio was 1.56 to 1. See "MEHC and EME: Liquidity—Financial Ratios—MEHC's Interest Coverage Ratio." MEHC did not declare or pay a dividend in 2003. MEHC's ability to pay dividends is dependent on EME's ability to pay dividends to MEHC. EME and its subsidiaries have certain dividend restrictions as discussed in the "MEHC and EME: Liquidity" section above. EME did not pay or declare a dividend to MEHC in 2003.

Edison International's investment in MEHC, through a wholly owned subsidiary, as of December 31, 2003, was $874 million. MEHC's investment in EME, as of December 31, 2003, was $1.9 billion. MEHC's and EME's independent accountants' audit opinion for the year ended December 31, 2003, contains an explanatory paragraph that indicates the consolidated financial statements have been prepared on the basis that EME will continue as a going concern and that the uncertainty about Edison Mission Midwest Holdings' ability to repay or refinance Edison Mission Midwest Holdings' $693 million of debt due in December 2004 raises substantial doubt about EME's ability to continue as a going concern. Accordingly, the consolidated financial statements do not include any adjustments that might result from the resolution of this uncertainty.

Edison Capital's ability to make dividend payments is currently restricted by debt covenants, which require Edison Capital, through a wholly owned subsidiary, to maintain a specified minimum net worth of $300 million. In October 2003, Edison Capital paid a $225 million cash dividend to Edison International. Edison Capital currently meets the minimum net worth covenant.

EDISON INTERNATIONAL (PARENT): MARKET RISK EXPOSURES

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

At December 31, 2003, the fair market value of Edison International (parent)'s 6-7/8% notes due September 2004 was $637 million. A 10% increase/decrease in market interest rates would have resulted in a $1.1 million decrease/increase in the fair market value of the parent company's 6-7/8% notes. At December 31, 2003, the fair market value of Edison International (parent)'s long-term note payable related to the quarterly income debt securities was $830 million. A 10% increase in market interest rates would have resulted in a $68 million decrease in the fair market value of the long-term note payable related to the quarterly income debt securities. A 10% decrease in market interest rates would have resulted in a $78 million increase in the fair market value of the long-term note payable related to the quarterly income debt securities.

EDISON INTERNATIONAL (PARENT): OTHER DEVELOPMENTS

Holding Company Proceeding

Edison International is a party to a CPUC holding company proceeding. See "SCE: Regulatory Matters—Other Regulatory Matters—Holding Company Proceeding" for a discussion of this matter.

EDISON INTERNATIONAL (CONSOLIDATED)

The following sections of the MD&A are on a consolidated basis. The section begins with a discussion of Edison International's consolidated results of operations and historical cash flow analysis. This is followed by discussions of discontinued operations, acquisitions and dispositions, critical accounting policies, new accounting principles, commitments and guarantees, off-balance sheet transactions and other developments.

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 share for the years ended December 31, 2003, 2002 and 2001, and the relative contributions by its subsidiaries.

In millions, except per share amounts	Earnings (Loss)			Earnings per Share		
Year Ended December 31,	2003	2002	2001	2003	2002	2001
Earnings (Loss) from Continuing Operations:						
Core Earnings:						
SCE	$ 872	$ 748	$ 408	$ 2.68	$ 2.30	$ 1.25
EME	28	82	113	0.08	0.26	0.35
Edison Capital	57	33	84	0.17	0.10	0.26
MEHC (stand alone)	(98)	(94)	(49)	(0.30)	(0.29)	(0.15)
Edison International (parent) and other	(80)	(114)	(132)	(0.24)	(0.35)	(0.41)
Edison International Core Earnings	779	655	424	2.39	2.02	1.30
SCE implementation of URG decision	—	480	—	—	1.47	—
SCE procurement and generation-related adjustment	—	—	1,978	—	—	6.07
Edison International Consolidated Earnings from Continuing Operations	779	1,135	2,402	2.39	3.49	7.37
Earnings (Loss) from Discontinued Operations	51	(58)	(1,367)	0.16	(0.18)	(4.19)
Cumulative Effect of Accounting Change	(9)	—	—	(0.03)	—	—
Edison International Consolidated	$ 821	$ 1,077	$ 1,035	$ 2.52	$ 3.31	$ 3.18

Earnings (Loss) from Continuing Operations

Edison International's 2003 earnings from continuing operations were $779 million, or $2.39 per share, compared with earnings of $1.1 billion, or $3.49 per share, in 2002 and earnings of $2.4 billion, or $7.37 per share, in 2001.

2003 vs. 2002

SCE's earnings from continuing operations were $872 million in 2003, compared to $748 million in 2002, excluding the $480 million gain. The $124 million increase results from the net effect of the resolution of several regulatory proceedings in 2002 and 2003. The 2003 proceedings include the CPUC decision on the allocation of certain costs between state and federal regulatory jurisdictions, tax impacts from the FERC rate case, and the final disposition of the PROACT which had been created to record the recovery of SCE's procurement-related obligations. The positive effects of these factors on 2003 earnings were partially offset by the implementation in 2002 of the CPUC's URG decision and PBR

rewards received in 2002. SCE's results also included higher depreciation expense and lower net interest income, partially offset by higher FERC and PBR revenue.

EME's earnings from continuing operations in 2003 were $28 million compared to $82 million in 2002. The decrease in earnings was primarily due to the asset impairment charge of $150 million, after tax, for Midwest Generation's peaking facilities, a reduction in capacity revenue for the Illinois power plants and a $32 million, after tax, asset impairment charge related to EME's investment in the Brooklyn Navy Yard project, partially offset by higher United States wholesale energy prices, increased generation from the Homer City plant and other net charges in 2002. These net charges, after tax, include write-offs totaling $66 million related to the cancellation of turbine orders, the suspension of the Powerton SCR project, and the impairment of goodwill and a $27 million loss from a settlement agreement that terminated the obligation to build additional generation in Chicago; partially offset by a gain of $43 million from the settlement of a postretirement employee benefit liability. EME's 2003 earnings included increased profitability from its interest in the Paiton project in Indonesia and its interest in the Sunrise project which commenced operation of Phase II in June 2003. These favorable items together with higher profitability from Contact Energy were partially offset by lower state tax benefits.

Earnings from continuing operations for Edison Capital were $57 million in 2003 compared with $33 million in 2002. The increase in earnings was primarily the result of the write-off in 2002 of an investment in aircraft leases with United Airlines totaling $34 million, after-tax, partially offset by a maturing investment portfolio which produces lower income.

The 2003 loss at MEHC (stand alone) increased by $4 million due to lower interest income and higher consulting fees.

The loss for Edison International (parent) and other decreased $34 million primarily from charges in 2002 associated with businesses the company exited.

2002 vs. 2001

SCE's earnings were $748 million in 2002, excluding the $480 million benefit related to the implementation of the CPUC's URG decision, compared to earnings of $408 million in 2001 excluding an adjustment of $2.0 billion to establish the PROACT and record the recovery of SCE's past procurement-related costs. The $340 million or 83% increase in SCE's earnings primarily reflects increased revenue resulting from the CPUC's 2002 decision in SCE's PBR proceeding, increased earnings from SCE's larger rate base in 2002 compared to 2001, lower interest expense, PBR rewards from prior years and increased income from San Onofre Units 2 and 3. The increase was partially offset by higher operating and maintenance expense.

Based on the CPUC's January 23, 2003 PROACT resolution, SCE was able to conclude that $3.6 billion in regulatory assets previously written off were probable of recovery through the rate-making process as of December 31, 2001. As a result, SCE's December 31, 2001 consolidated income statement included a $3.6 billion credit to provisions for regulatory adjustment clauses and a $1.5 billion charge to income tax expense, to reflect the $2.1 billion (after tax) credit to earnings.

EME's earnings from continuing operations in 2002 were $82 million, compared to $113 million in 2001. The decrease in earnings was primarily due to lower west coast energy prices, unplanned outages at the Homer City plant, gains related to gas swaps from EME's oil and gas activities, the implementation of a new accounting standard for derivatives in 2001, and other net charges during 2002 totaling $50 million, after tax, or $0.15 per share. These net charges included a $27 million loss from a settlement agreement that terminated the obligation to build additional generation in Chicago and a $66 million write-down of assets related to the cancellation of turbine orders, the suspension of the Powerton SCR project, and an

impairment of goodwill, partially offset by a gain of $43 million from the settlement of a postretirement employee benefit liability. The decrease in earnings from continuing operations was partially offset by improved operating results at EME's Illinois, Loy Yang B and ISAB plants, income from the Paiton project in Indonesia, and lower state income taxes.

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

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

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

Operating Revenue

SCE's retail sales represented approximately 91%, 96% and 94% of electric utility revenue in 2003, 2002, and 2001, respectively. Due to warmer weather during the summer months, electric utility revenue during the third quarter of each year is significantly higher than other quarters.

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

In millions	Year ended December 31,	2003 vs. 2002	2002 vs. 2001
Electric utility revenue			
Rate changes (including surcharges)		$ (677)	$ 563
Direct access credit		471	(604)
Sales volume changes		(60)	696
Sales for resale		394	(11)
Other (including intercompany transactions)		20	(59)
Total		$ 148	$ 585

Total electric utility revenue increased by $148 million in 2003 (as shown in the table above). The reduction in electric utility revenue due to rate changes resulted from the implementation of a CPUC-approved customer rate-reduction plan effective August 1, 2003, partially offset by the recognition of revenue from the CPUC-authorized temporary surcharge collected in 2002, used to recover costs incurred in 2003 (see "SCE: Regulatory Matters—Generation and Power Procurement—Temporary Surcharges"). The increase in electric utility revenue due to direct access credits resulted from a net 1¢-per-kWh decrease in credits given to direct access customers. The reduction in electric revenue resulting from changes in sales volume was mainly due to an increase in the amount allocated to the CDWR for bond and direct access exit fees (see discussion below), partially offset by an increase in kWh sold due to warmer weather in 2003 as compared to 2002. Sales for resale revenue increased due to a greater amount of excess energy at SCE in 2003 as compared to 2002. As a result of CDWR contracts allocated to SCE, excess energy from SCE sources may exist at certain times and is resold in the energy markets.

Electric utility revenue increased by $585 million in 2002 as compared to 2001 (as shown in the table above). The increase in electric utility revenue due to rate changes resulted from a 3¢-per-kWh surcharge authorized by the CPUC as of March 27, 2001. The decrease in electric utility revenue due to direct access credits resulted from an increase in credits given to direct access customers due to a significant increase in the number of direct access customers. The increase in electric utility revenue resulting from changes in sales volume was primarily due to SCE providing its customers with a greater volume of

energy generated from its own generating plants and power-purchase contracts, rather than the CDWR purchasing power on behalf of SCE's customers.

Amounts SCE bills and collects from its customers for electric power purchased and sold by the CDWR to SCE's customers (beginning January 17, 2001), CDWR bond-related costs (beginning November 15, 2002) and direct access exit fees (beginning January 1, 2003) are remitted to the CDWR and are not recognized as revenue by SCE. These amounts were $1.7 billion, $1.4 billion, and $2.0 billion for the years ended December 31, 2003, 2002, and 2001, respectively.

Nonutility power generation revenue increased in both 2003 and 2002. The 2003 increase was primarily due to increased electric revenue from EME's Homer City facilities and Contact Energy projects, partially offset by lower capacity revenue from EME's Illinois plants due to a deduction in megawatts under contract with Exelon Generation. The increases at EME's Homer City facilities were primarily due to increased generation and higher energy prices. The increases at EME's Contact Energy projects were primarily due to higher wholesale energy prices, higher generation and an increase in the average exchange rate. The 2002 increase was primarily due to EME's consolidation of Contact Energy for a full year in 2002, compared to a partial year in 2001 (ownership interest increased to 51%, effective June 1, 2001), and increased revenue from the Illinois plants and First Hydro plant. These increases were partially offset by decreased revenue from EME's Homer City facilities.

During 2003, 2002 and 2001, 22%, 40% and 42%, respectively, of nonutility power generation revenue was derived under three power-purchase agreements between EME's wholly owned subsidiary, Midwest Generation, and Exelon Generation Company, a subsidiary of Exelon Corporation. Revenue under these agreements was $708 million in 2003 and $1.1 billion in both 2002 and 2001. Midwest Generation expects to be less dependent on Exelon Generation as a major customer during 2004 due to Exelon Generation's release of 3,262 MW of capacity from the coal units and 1,614 MW of capacity from the Collins Station. In 2004, 2,383 MW of capacity from the coal units and 1,084 MW of capacity from the Collins Station will remain subject to the power-purchase agreements. The power-purchase agreements terminate at the end of 2004. Exelon Corporation is the holding company of ComEd and PECO Energy Company, major utilities located in Illinois and Pennsylvania. If Exelon Generation were to fail, become unable to fulfill, or choose to terminate some of its obligations under these power-purchase agreements, Midwest Generation might not be able to find another customer on similar terms for the output of the Illinois plants. Any material failure by Exelon Generation to make payments to Midwest Generation under these power-purchase agreements could result in a shortfall of cash available for Midwest Generation to meet its obligations. A default by Midwest Generation in meeting its obligations could in turn have a material adverse effect on EME.

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

Financial services and other revenue increased in 2003 and decreased in 2002. The 2003 increase was primarily due to Edison Capital's recording of the cumulative impact of a change in its effective state tax rate on leveraged leases in 2002 (that was substantially offset by tax benefits), partially offset by Edison Capital's maturing lease portfolio, the termination of a major contract at a nonutility subsidiary providing operation and maintenance services and no nonutility real estate sales in 2003, as compared to 2002, for another subsidiary. In addition to the above, the 2002 decrease also reflected the impact of adopting the equity method of accounting in conformance with the infrastructure funds accounting policies.

Operating Expenses

Fuel expense increased for both 2003 and 2002. The increase in 2003 was primarily due to increased generation at EME's Homer City facilities primarily resulting from outages experienced during the first two quarters of 2002, increased fuel costs at EME's Contact Energy projects primarily due to higher gas prices and an increase in the value of the New Zealand dollar compared to the United States dollar. The increase in 2002 was primarily related to EME's consolidation of Contact Energy for a full year in 2002 as compared to a partial year in 2001, increased pumping power costs from EME's First Hydro plant, increased fuel costs from EME's Illinois plants and an increase at SCE related to a payment received under a settlement agreement with Peabody associated with Mohave. The 2002 increase was partially offset by decreased fuel costs from EME's Homer City facilities.

Purchased-power expense increased in 2003 and decreased in 2002. The 2003 increase was mainly due to higher expenses resulting from SCE's resumption of power procurement on January 1, 2003. The higher expenses resulted from an increase in the number of bilateral contracts entered into during 2003 and an increase in energy purchased in 2003. The increase also includes higher expenses related to power purchased by SCE from QFs, mainly due to higher spot natural gas prices in 2003 as compared to 2002. The 2002 decrease resulted primarily from lower expenses at SCE related to power purchased from QFs, bilateral contracts and interutility contracts, mainly due to lower spot natural gas prices in 2002 as compared to 2001. In addition, the decrease reflects the absence of PX/ISO purchased-power expense after mid-January 2001.

Federal law and CPUC orders required SCE to enter into contracts to purchase power from QFs at CPUC-mandated prices. These contracts expire on various dates through 2025. Energy payments to gas-fired cogeneration QFs are generally tied to spot natural gas prices. Effective May 2002, energy payments for most renewable QFs were converted to a fixed price of 5.37¢-per-kWh, compared with an average of 3.1¢-per-kWh during the period of January and April 2002. During 2003, spot natural gas prices were higher compared to the same period in 2002. During 2002, spot natural gas prices were significantly lower than the same periods in 2001.

Provisions for regulatory adjustment clauses – net decreased in 2003 and increased in 2002. The 2003 decrease was mainly due to lower overcollections used to recover SCE's PROACT balance, the implementation of the CPUC-authorized customer rate-reduction plan, a net increase in energy procurement costs and favorable resolution of several regulatory proceedings. The 2003 proceedings include the CPUC decision on the allocation of certain costs between state and federal regulatory jurisdictions and the final disposition of the PROACT. The decrease was partially offset by the implementation of the CPUC decision related to URG and the PBR mechanism, as well as the impact of other regulatory actions recorded in 2002. The 2002 increase was primarily due to the establishment of the PROACT regulatory asset in 2001, overcollections used to recover the PROACT balance and revenue collected to recover the rate reduction bond regulatory asset, partially offset by the impact of SCE's implementation of the CPUC decision related to URG and the PBR mechanism, as well as the impact of other regulatory actions.

As a result of the URG decision received in 2002, SCE reestablished regulatory assets previously written off (approximately $1.1 billion) related to its nuclear plant investments, purchased-power settlements and flow-through taxes, and decreased the PROACT balance by $256 million, all retroactive to January 1, 2002. The impact of the URG decision is reflected in the 2002 financial statements as a credit (decrease) to the provisions for regulatory adjustment clauses of $644 million, partially offset by an increase in deferred income tax expense of $164 million, for a net credit to earnings of $480 million. As a result of the CPUC decision that modified the PBR mechanism, SCE recorded a $136 million credit (decrease) to the provisions for regulatory adjustment clauses in the second quarter of 2002, to reflect undercollections in CPUC-authorized revenue resulting from changes in retail rates.

Other operation and maintenance expense increased in both 2003 and 2002 primarily due to increases at both SCE and EME.

SCE's other operating and maintenance expense increase in 2003 was mainly due to higher health-care costs, higher spending on certain CPUC-authorized programs, higher transmission access charges and costs incurred in 2003 related to the removal of dead, dying and diseased trees and vegetation associated with the bark beetle infestation (see "SCE: Regulatory Matters—Other Regulatory Matters—Catastrophic Event Memorandum Account"). SCE's other operation and maintenance expense increase in 2002 was primarily due to the San Onofre Unit 2 refueling outage in 2002, increases in transmission and distribution maintenance and inspection activities, and temporary cost containment efforts that took place in 2001. The 2002 increases were partially offset by lower expenses related to balancing accounts.

EME's other operation and maintenance expense increased in 2003 due to an increase in transmission costs due to higher retail sales generated by EME's Contact Energy and an increase in the value of the New Zealand dollar, compared to the United States dollar. EME's other operation and maintenance expense increased in 2002 mainly due to an increase in transmission costs, primarily due to consolidating Contact Energy, effective June 1, 2001 and an increase in operating leases due to the sale-leaseback transactions for the Homer City and Powerton-Joliet power facilities. There were no comparable lease costs for the Homer City facilities through the period ended December 2001 and the Powerton-Joliet power facilities through the period ended August 2000. See "Off-Balance Sheet Transactions—EME's Off-Balance Sheet Transactions—Sale-Leaseback Transactions," for discussion of the financial impact of sale-leaseback transactions. In addition, in 2002, EME recorded a $45 million charge related to a settlement of EME's Chicago In-City obligation. These increases were partially offset by a gain recorded related to the termination of postretirement benefits as discussed below.

The settlement of postretirement employee benefit liability in 2002 relates to a retirement health care and other benefits plan for union-represented employees at the Illinois plants that expired on June 15, 2002. In October 2002, Midwest Generation reached an agreement with its union-represented employees on new benefits plans, which extend from January 1, 2003 through June 15, 2006. Midwest Generation continued to provide benefits at the same level as those in the expired agreement until December 31, 2002. The accounting for postretirement benefits liabilities has been determined on the basis of a substantive plan under an accounting standard for postretirement benefits other than pensions. A substantive plan means that Midwest Generation assumed, for accounting purposes, it would provide for postretirement health care benefits to union-represented employees following conclusion of negotiations to replace the current benefits agreement, even though Midwest Generation had no legal obligation to do so. Under the new agreement, postretirement health care benefits will not be provided. Accordingly, Midwest Generation treated this as a plan termination in accordance with this accounting standard and recorded a pre-tax gain of $71 million during the fourth quarter of 2002.

Asset impairment expense in 2003 consisted of $245 million related to the impairment of eight small peaking plants owned by EME's wholly owned subsidiary, Midwest Generation, $53 million to write-down the estimated net proceeds from the planned sale of EME's Brooklyn Navy Yard project and $6 million related to EME's write-down of its investment in the Gordonsville project due to its planned disposition (see "Acquisitions and Dispositions" for further discussion). The impairment charge related to the peaking plants resulted from a revised long-term outlook for capacity revenue from the peaking plants. The lower capacity revenue outlook is the result of a number of factors, including higher long-term natural gas prices and the current generation overcapacity in the MAIN region market. See "MEHC and EME: Liquidity—Financial Ratios—EME's Recourse Debt to Recourse Capital Ratio." The book value of these assets was written down from $286 million to an estimated fair market value of $41 million. The estimated fair market value was determined based on discounting estimated future pre-tax cash flows using a 17.5% discount rate. Asset impairment expense in 2002 consisted of $61 million related to the write-off of capitalized costs associated with EME's termination of equipment purchase

contracts and $25 million related to the write-off of capitalized costs associated with EME's suspension of its Powerton Station selective catalytic reduction major capital environmental improvements project at its Illinois plants.

Depreciation, decommissioning and amortization expense increased in both 2003 and 2002. The 2003 increase was mainly due to an increase in depreciation expense associated with SCE's additions to transmission and distribution assets, an increase in SCE's nuclear decommissioning expense and higher depreciation expense at EME's Contact Energy projects associated with the Taranaki Station acquisition. The 2003 increase also included additional depreciation expense resulting from the termination of EME's Midwest Generation equipment lease in August 2002, and an increase in amortization expense at Edison Capital resulting from a change from the cost method to the equity method of accounting for its fund investments in 2002. The 2003 increase was partially offset by a change in the amortization period for SCE's San Onofre recorded in the third quarter of 2002 based on the implementation of a CPUC decision. The increase in 2002 was mainly due to an increase in depreciation expense associated with SCE's additions to transmission and distribution assets and an increase in SCE's nuclear decommissioning expense. A 1994 CPUC decision allowed SCE to accelerate the recovery of its nuclear-related assets while deferring the recovery of its distribution-related assets for the same amount. Beginning in January 2002, the CPUC approved the commencement of recovery of SCE's deferred distribution assets. In addition, the increases reflect amortization expense on the nuclear regulatory asset reestablished during second quarter 2002 based on the URG decision. These 2002 increases were partially offset by lower depreciation expense at EME's Homer City facilities due to the sale-leaseback transaction that took place in December 2001, as well as ceasing the amortization of goodwill in January 1, 2002.

Other Income and Deductions

Interest and dividend income decreased in 2003 and increased in 2002. The 2003 decrease was mainly due to lower interest income on the PROACT balance at SCE as well as lower interest income from lower average cash balances at SCE, compared to the same period in 2002. The 2002 increase was mainly due to the interest income earned on the PROACT balance at SCE. The 2002 increase was partially offset by lower interest income due to lower average cash balances and lower interest rates at SCE, EME and Edison Capital during 2002, as compared to 2001 and lower earnings from Edison Capital's investments.

Equity in income from partnerships and unconsolidated subsidiaries – net increased in 2003 and decreased in 2002. The 2003 increase was primarily due to an increase in EME's income from the Big 4 projects, Four Star Oil & Gas and the Sunrise project. Also contributing to the 2003 increase were increased earnings from Edison Capital's infrastructure funds. The 2002 decrease was primarily due to a decrease in EME's income from the Big 4 projects and Four Star Oil & Gas, partially offset by an increase in EME's income from the Paiton Energy and ISAB projects. EME's third quarter equity in income from its domestic energy projects is materially higher than equity in income related to other quarters for the year due to warmer weather during the summer months and because a number of EME's domestic energy projects, located on the West Coast, have power sales contracts that provide for higher payments during the summer months.

Other nonoperating income increased in 2003 and decreased in 2002. The 2003 increase was mainly due to SCE's recognition of 2000 and 2001 Palo Verde performance rewards approved by the CPUC during 2003, as well as higher gains on the sale of EME's development projects in 2003 as compared to 2002. The increase was almost entirely offset by property condemnation settlements received at SCE in 2002, with no comparable settlements received in 2003 and lower foreign exchange gains at Edison Capital in 2003, compared to 2002. The 2002 decrease was primarily due to a decrease at EME, partially offset by increases at SCE and Edison Capital. The decrease at EME was mainly due to foreign exchange losses in 2002 compared to foreign exchange gains in 2001, lower gains on the sale of EME's interest in energy projects in 2002 compared to 2001, as well as a gain on early extinguishment of debt in 2001. The 2002

increase at SCE was primarily due to property condemnation settlements received, partially offset by PBR incentive awards for 1999 and 2000, which were approved by the CPUC and recorded in 2001. The increase at Edison Capital was primarily due to higher foreign exchange gains in 2002 compared to 2001.

Interest expense – net of amounts capitalized decreased in both 2003 and 2002. The 2003 decrease was due to lower interest expense at SCE due to the accrual of interest in 2002 related to the 2001 and early 2002 suspension of payments for purchased power (these suspended payments were paid in March 2002), as well as lower interest expense on SCE's long-term debt resulting from the early retirement of debt. The 2003 decrease was partially offset by higher interest costs at EME's Illinois plants due to a downgrade of the credit rating of Edison Mission Midwest Holdings (see "MEHC and EME: Liquidity—EME's Credit Ratings") and higher levels of borrowings at EME's Contact Energy related to the Taranaki Station acquisition. Interest expense – net in 2003 reflects a change in the classification of dividend payments on preferred securities to interest expense – net from dividends on preferred securities. Effective July 1, 2003, dividend payments on preferred securities subject to mandatory redemption are included as interest expense based on the adoption of a new accounting standard. The new standard did not allow for prior period restatements, therefore dividends on preferred securities subject to mandatory redemption for the first six months of 2003 are not included in interest expense – net of amounts capitalized in the consolidated statements of income. The 2002 decrease is mainly due to: lower long-term debt balances at Edison Capital as compared to 2001; lower short-term debt balances at Edison International (parent) and all of the principal operating subsidiaries compared to 2001; and lower interest expense at SCE related to the suspension of payments for purchased power during 2001, which were subsequently paid in early 2002. The decrease was partially offset by: an increase in interest expense on long-term debt at SCE due to higher long-term debt balances; an increase in long-term debt interest expense at MEHC resulting from the debt financing that took place in July 2001; and the consolidation of Contact Energy at EME.

Other nonoperating deductions increased in both 2003 and 2002. The 2003 increase was primarily due to the reversal of accruals for regulatory matters in 2002, partially offset by a goodwill impairment charge associated with EME's Citizens Power acquisition resulting from adoption of an accounting standard in 2002, as well as lower foreign exchange losses at Edison Capital. The adoption of the standard was not material to Edison International; therefore the impact was recorded in other nonoperating deductions, rather than as a cumulative effect of a change in accounting principle. The 2002 increase was mainly due to the goodwill impairment charge at EME, partially offset by the reversal of accruals for regulatory matters at SCE in 2002.

Income Taxes

Income tax expense decreased in both 2003 and 2002. The 2003 and 2002 decreases were primarily due to reductions in pre-tax income. The 2003 decrease also resulted from the favorable resolution of a FERC rate case at SCE. The 2003 decrease was partially offset by the reestablishment of tax-related regulatory assets upon implementation of the URG decision at SCE and the cumulative adjustment to deferred tax balances at Edison Capital to reflect changes in its effective state tax rate, both recorded in 2002. The 2002 decrease also resulted from the reestablishment of tax-related regulatory assets upon implementation of the URG decision at SCE, a cumulative adjustment to deferred tax balances at Edison Capital to reflect changes in its effective state tax rate and favorable resolution of tax audits at SCE.

Edison International's composite federal and state statutory rate was approximately 40% for all years presented. The lower effective tax rate of 21.5% realized in 2003 was primarily due to the resolution of a FERC rate case at SCE, recording the benefit of favorable resolution of tax audit issues at SCE and the benefits received from low-income housing and production tax credits at Edison Capital. The lower effective tax rate of 25.6% realized in 2002 was primarily due to the reestablishment of tax-related regulatory assets upon implementation of the URG decision at SCE, a cumulative adjustment to deferred

tax balances at Edison Capital to reflect changes in its effective state tax rate, the favorable resolution of tax audit issues at SCE and the benefits received from low-income housing and production credits at Edison Capital.

Earnings (Loss) from Discontinued Operations

Edison International's earnings from discontinued operations in 2003 were $51 million, including a $44 million (after-tax) gain on the sale of SCE's fuel oil pipeline business. Edison International's loss from discontinued operations in 2002 represent the one-time asset impairment charge of $77 million (after tax) resulting from EME's Lakeland project being placed into administrative receivership in the United Kingdom, offset by $22 million in 2002 operating results from the Lakeland project. See further discussion at "Discontinued Operations" and "Acquisitions and Dispositions." The 2002 loss also includes minor adjustments related to the sale of EME's Fiddler's Ferry and Ferrybridge coal stations and the sale of a majority of Edison Enterprises (a nonutility subsidiary of Edison International that formerly provided retail services) assets in 2001. The 2001 loss includes impairment charges resulting from the sale of the Fiddler's Ferry and Ferrybridge plants and the majority of Edison Enterprises' assets, as well as operating results from the discontinued entities.

Cumulative Effect of Accounting Change – net of tax

Edison International's results for 2003 include a $9 million charge at EME for the cumulative effect of an accounting change related to the new accounting standard for recording asset retirement obligations adopted by Edison International in January 2003. As SCE follows accounting principles for rate-regulated enterprises, implementation of this new standard did not affect earnings. (See "New Accounting Principles.")

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 by operating activities:

In millions Year ended December 31,	2003	2002	2001
Continuing operations	$ 3,359	$ 2,241	$ 3,121
Discontinued operations	(52)	80	(147)
	$ 3,307	$ 2,321	$ 2,974

The 2003 increase in cash provided by operating activities from continuing operations was mainly due to SCE's March 2002 repayment of past-due obligation. The change was also due to timing of cash receipts and disbursements related to working capital items at both SCE and EME. The 2002 decrease in cash provided by operating activities from continuing operations was mainly due to SCE's March 2002 repayment of past-due obligations, partially offset by higher overcollections used to recover regulatory assets resulting from the CPUC-approved surcharges (1¢-per-kWh in January 2001 and 3¢-per-kWh in June 2001) and an increase in operating cash flow from EME resulting from the timing of cash payments related to working capital items.

Cash used by operating activities from discontinued operations in 2003 primarily reflects operating activities at SCE's fuel oil pipeline business. Cash provided by operating activities from discontinued

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

Cash Flows from Financing Activities

Net cash used by financing activities:

In millions Year ended December 31,	2003	2002	2001
Continuing operations	$ (2,006)	$ (2,582)	$ (379)
Discontinued operations	—	(19)	(1,178)
	$ (2,006)	$ (2,601)	$(1,557)

Cash used by financing activities from continuing operations in 2003 mainly consisted of long-term and short-term debt payments at SCE and EME.

During the first quarter of 2003, Edison International (parent) repurchased approximately $132 million of the outstanding $750 million of its 6-7/8% notes due September 2004. No repurchases were made during the remainder of 2003. SCE's financing activities during 2003 included an exchange offer of $966 million of 8.95% variable rate notes due November 2003 for $966 million of new series first and refunding mortgage bonds due February 2007. In addition, during 2003, SCE repaid $125 million of its 6.25% bonds, the outstanding balance of $300 million of a $600 million one-year term loan due March 3, 2003, $300 million on its revolving line of credit, and $700 million of a term loan due March 2005. The $700 million term loan was retired with a cash payment of $500 million and $200 million drawn on a $700 million credit facility that expires in 2006. EME's financing activity during 2003 includes an $800 million secured loan received by EME's subsidiary, Mission Energy Holdings International, combined with borrowings of $800 million and $275 million in borrowings by Contact Energy, EME's 51% owned subsidiary, used to finance Contact Energy's acquisition of the Taranaki Combined Cycle power station (see "Acquisitions and Dispositions" for further discussion of the acquisition). EME's financing activity in 2003 also included debt service payments of $911 million related to Tranche A and $116 million related to Tranche B of Edison Mission Energy Holdings' credit facility, repayment of $167 million on the Coal and Capex facility guaranteed by EME, debt service payments of $118 million related to three of EME's subsidiaries, and repayment of $31 million of debt obligations due from EME's acquisition of the Spanish Hydro project.

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

Cash used by financing activities from continuing operations in 2001 consisted of long-term debt repayments at EME and short-term debt repayments at the parent company and at EME. The uses of cash

were partially offset by the issuance of long-term debt at EME of $1.0 billion and at MEHC of $1.2 billion.

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

In December 1997, $2.5 billion of rate reduction notes were issued on behalf of SCE by SCE Funding LLC, a special purpose entity. These notes were issued to finance the 10% rate reduction mandated by state law. The proceeds of the rate reduction notes were used by SCE Funding LLC to purchase from SCE an enforceable right known as transition property. Transition property is a current property right created by the electric industry restructuring legislation and a financing order of the CPUC and consists generally of the right to be paid a specified amount from nonbypassable rates charged to residential and small commercial customers. The rate reduction notes are being repaid over 10 years through these nonbypassable residential and small commercial customer rates, which constitute the transition property purchased by SCE Funding LLC. The remaining series of outstanding rate reduction notes have scheduled maturities through 2007, with interest rates ranging from 6.38% to 6.42%. The notes are collateralized by the transition property and are not collateralized by, or payable from, assets of SCE or Edison International. SCE used the proceeds from the sale of the transition property to retire debt and equity securities. Although, as required by accounting principles generally accepted in the United States, SCE Funding LLC is consolidated with SCE and the rate reduction notes are shown as long-term debt in the consolidated financial statements, SCE Funding LLC is legally separate from SCE. The assets of SCE Funding LLC are not available to creditors of SCE or Edison International and the transition property is legally not an asset of SCE or Edison International.

Cash Flows from Investing Activities

Net cash provided (used) by investing activities:

In millions Year ended December 31,	2003	2002	2001
Continuing operations	$ (1,725)	$ (1,331)	$ (424)
Discontinued operations	150	2	1,125
	$ (1,575)	$ (1,329)	$ 701

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

Additions to SCE's property and plant during 2003 were approximately $1.2 billion, primarily for transmission and distribution assets. EME's capital additions in 2003 were $127 million primarily for new plant and equipment related to EME's Illinois plants, its Homer City facilities, and Contact Energy projects. EME's 2003 investing activity also included $275 million paid by Contact Energy for the acquisition of the Taranaki Combined Cycle power station (see "Acquisitions and Dispositions" for further discussion of the acquisition).

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

related to three turbines. These increases were partially offset by proceeds from the sale of various EME projects.

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

Investing cash flows from discontinued operations in 2003 represents the proceeds received from SCE's sale of its fuel oil pipeline business. Cash flows from investing activities from discontinued operations in 2001 includes the proceeds received from EME's sale of Ferrybridge and Fiddler's Ferry power plants on December 21, 2001.

Nuclear decommissioning costs are recovered in utility rates. These costs are expected to be funded from independent decommissioning trusts that receive SCE contributions of approximately $32 million per year. The fair value of decommissioning SCE's nuclear power facilities is $2.1 billion as of December 31, 2003, based on site-specific studies performed in 2001 for San Onofre and Palo Verde. As of December 31, 2003, the decommissioning trust balance was $2.5 billion. The CPUC has set certain restrictions related to the investments of these trusts. Contributions to the decommissioning trusts are reviewed every three years by the CPUC. The contributions are determined from an analysis of estimated decommissioning costs, the current value of trust assets and long-term forecasts of cost escalation and after-tax return on trust investments. Favorable or unfavorable investment performance in a period will not change the amount of contributions for that period. However, trust performance for the three years leading up to a CPUC review proceeding will provide input into future contributions. SCE's costs to decommission San Onofre Unit 1 are paid from the nuclear decommissioning trust funds. These withdrawals from the decommissioning trusts are netted with the contributions to the trust funds in the Consolidated Statements of Cash Flows.

DISCONTINUED OPERATIONS

On July 10, 2003, the CPUC approved SCE's sale of certain oil storage and pipeline facilities to Pacific Terminals LLC for $158 million. In third quarter 2003, SCE recorded a $44 million after-tax gain to shareholders. In 2003, the results of SCE's oil storage and pipeline facilities unit have been accounted for as a discontinued operation in the consolidated financial statements.

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

On December 21, 2001, EME completed the sale of the Fiddler's Ferry and Ferrybridge coal stations located in the United Kingdom to two wholly owned subsidiaries of AEP. The net proceeds from the sale (£643 million) were used to repay borrowings outstanding under the existing debt facility related to the

acquisition of the plants. In addition, the buyers acquired other assets and assumed specific liabilities associated with the plants. EME recorded a charge of $1.9 billion ($1.1 billion after tax) related to the loss on sale. The $1.9 billion charge includes the asset impairment charge recorded in third quarter 2001 to reduce the carrying value of the assets held for sale to reflect estimated fair value less the cost to sell and related currency adjustments. EME had acquired the plants in 1999 for approximately $2.0 billion (£1.3 billion).

In August 2001, Edison Enterprises, a wholly owned subsidiary of Edison International, sold a subsidiary principally engaged in the business of providing residential security services and residential electrical warranty repair services. In October 2001, Edison Enterprises completed the sale of substantially all of its assets of another subsidiary (engaged in the business of commercial energy management) to the subsidiary's current management. As a result, Edison International recorded a charge of $127 million (after tax) in 2001 related to the losses on these sales. The impairment charges recorded in 2001 to reduce the carrying value of these investments held for sale to reflect the estimated fair value less cost to sell are included in the $127 million charge. For all years presented, the results of the Fiddler's Ferry and Ferrybridge coal stations and Edison Enterprises subsidiaries sold during 2001 have been reflected as discontinued operations in the consolidated financial statements.

ACQUISITIONS AND DISPOSITIONS

On December 31, 2003, EME agreed to sell its 50% partnership interest in Brooklyn Navy Yard Cogeneration Partners L.P. to a third party. Completion of the sale, currently expected in the first quarter of 2004, is subject to closing conditions, including obtaining regulatory approval. Proceeds from the sale are expected to be approximately $42 million. EME recorded an impairment charge of $53 million during the fourth quarter of 2003 related to the planned disposition of this investment.

On December 12, 2003, EME agreed to sell 100% of its stock of Edison Mission Energy Oil & Gas, which in turn holds minority interests in Four Star Oil & Gas, to Medicine Bow Energy Corporation. Following receipt of regulatory approvals and satisfaction of all other closing conditions, EME completed this sale on January 7, 2004. Proceeds from the sale were approximately $100 million. EME expects to record a pre-tax gain on the sale of approximately $47 million during the first quarter of 2004.

On November 21, 2003, Gordonsville Energy Limited Partnership, in which EME owns a 50% interest, completed the sale of the Gordonsville cogeneration facility to Virginia Electric and Power Company. Proceeds from the sale, including distribution of a debt service reserve fund, were $36 million. EME recorded an impairment charge of $6 million during the second quarter of 2003 related to the planned disposition of this investment.

On July 17, 2003, SCE signed an option agreement with Sequoia Generating LLC, a subsidiary of InterGen, to acquire Mountainview Power Company LLC, the owner of a new 1,054-megawatt, combined-cycle, natural gas-fired power plant currently being developed in Redlands, California. Mountainview Power Company LLC would sell all the output of the power plant to SCE pursuant to a 30-year tolling power-purchase agreement. The power-purchase agreement would be a cost-based contract providing for recovery of investment, fixed and variable costs, and a regulated rate of return, over the 30-year life of the contract. On December 18, 2003, the CPUC approved the Mountainview power-purchase agreement, subject to SCE receiving a FERC decision approving the agreement without any modifications that would have potential rate impacts. On February 25, 2004, the FERC granted conditional approval of the Mountainview power-purchase agreement. On March 1, 2004, a CPUC administrative law judge issued a proposed decision that would accept the conditions in the FERC approval of the power-purchase agreement. The matter is scheduled to be considered by the CPUC at its meeting on March 16, 2004. On February 28, 2004, SCE exercised its option to purchase Mountainview Power LLC. SCE currently anticipates that it will close the purchase before the end of March 2004 and recommence construction of

the project immediately thereafter. SCE estimates that the project will be completed in March 2006 at a cost of approximately $600 million, excluding financing costs. SCE expects to finance the capital costs of the project with debt and equity at the utility level consistent with its authorized capital structure.

On July 10, 2003, the CPUC approved a joint application filed by SCE and Pacific Terminals LLC, requesting authorization for the sale of certain oil storage and pipeline facilities by SCE to Pacific Terminals for $158 million. The sale closed on July 31, 2003 and resulted in a $44 million after-tax gain to shareholders recorded in the third quarter of 2003.

On March 3, 2003, Contact Energy, EME's 51% owned subsidiary, completed a transaction with NGC Holdings Ltd. to acquire the Taranaki Combined Cycle power station and related interests. The Taranaki station is a 357 MW combined cycle, natural gas-fired plant located near Stratford, New Zealand. Consideration for the Taranaki station consisted of a cash payment of approximately $275 million, which was initially financed with bridge loan facilities. The bridge loan facilities were subsequently repaid with proceeds from Contact Energy's issuance of long-term United States dollar denominated notes.

CRITICAL ACCOUNTING POLICIES

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

Asset Impairment

Edison International evaluates long-lived assets whenever indicators of potential impairment exist. Accounting standards require that if the undiscounted expected future cash flow from a company's assets or group of assets (without interest charges) is less than its carrying value, an asset impairment must be recognized in the financial statements. The amount of impairment is determined by the difference between the carrying amount and fair value of the asset.

The assessment of impairment is a critical accounting estimate because significant management judgment is required to determine: (1) if an indicator of impairment has occurred, (2) how assets should be grouped, (3) the forecast of undiscounted expected future cash flow over the asset's estimated useful life to determine if an impairment exists, and (4) if an impairment exists, the fair value of the asset or asset group. Factors 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 the second quarter of 2003, EME assessed the impairment of its Illinois plants. EME has grouped the Illinois plants into two asset groups: coal-fired power plants and the small peaker plants. Management judgment was required to make this assessment based on the lowest level of cash flow that was viewed by management as largely independent of each other. The expected future undiscounted cash flow from EME's merchant power plants is a critical accounting estimate because: (1) estimating future prices of energy and capacity in wholesale energy markets is susceptible to significant change, and (2) the forecast is over an extended time period due to the estimated useful life (15 to 33.75 years) of power plants, and (3) the impact of an impairment on EME's consolidated financial position and results of operations would be material. The expected undiscounted future cash flow from the small peaker plants did not exceed the carrying value of that asset group. The book value of these assets was written down from $286 million to an estimated fair market value of $41 million. The estimated fair market value was determined based on discounting estimated future pretax cash flows using a 17.5% discount rate. The impairment charge relating to the peaking plants resulted from a revised long-term outlook for capacity revenue from the peaking plants. The lower capacity revenue outlook is the result of a number of factors,

including higher long-term natural gas prices and the current generation overcapacity in the MAIN region market. See "MEHC and EME: Market Risk Exposures—Commodity Price Risk—Illinois Plants."

In addition to the asset impairment charge related to the small peaking plants in 2003, EME's indirect subsidiary, Midwest Generation, also reported an impairment charge of $475 million, after tax, related to the 2,698 MW gas-fired Collins Station in its second quarter report on Form 10-Q. The impairment charge resulted from a write-down of the book value of the Collins Station capitalized assets from $858 million to an estimated fair market value of $78 million. The impairment charge by Midwest Generation is not reflected in the operating results of EME because the lease related to the Collins Station is treated in EME's financial statements as an operating lease and not as an asset and, therefore, is not subject to impairment for accounting purposes. See "MEHC and EME: Liquidity—Financial Ratios—EME Recourse Debt to Recourse Capital Ratio."

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

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

Edison International also would record an impairment charge if a decision is made (which generally occurs when Edison International enters into an agreement to sell an asset) to dispose of an asset and the fair value is less than Edison International's book value. The accounting standards require the following criteria to be met to classify an asset held for sale:

1. management approves the action and commits to a plan to sell an asset, which is generally evidenced by the signing of an asset sales agreement or Board of Directors approval;

2. the long-lived asset (asset group) is generally deemed to be available for immediate sale and conditions for sale is subject only to the terms and conditions customary for sale of such assets;

3. management has actively engaged in a program to locate a buyer and has initiated other such actions required to complete the plan to sell the asset;

4. the sale is probable and the transfer of the asset is expected to be completed within one year;

5. the asset is being marketed at a price that is believed to be reasonable in relation to fair value; and

6. management believes that it is unlikely that significant changes to the plan that asset will be made or that the plan will be withdrawn.

EME has engaged investment bankers to market for sale its international project portfolio which commenced during the first quarter of 2004. Completion of the sale of all or part of EME's international project portfolio is contingent on receiving acceptable offers in terms of both price and terms and conditions related to risk factors. Due to the uncertainty regarding completion of the sale of all or part of the international project portfolio through the current offering process, management has concluded that it has not met all of the requirements listed above at December 31, 2003. EME's book value of its international project portfolio was approximately $2.2 billion at December 31, 2003. Edison International cannot predict with certainty whether EME will be able to sell these assets at or above book value.

During 2003, EME met the asset held for sale criteria under the accounting standards regarding its investment in the Gordonsville and Brooklyn Navy projects and recorded an impairment based on the net proceeds expected from the sale of $6 million and $53 million, respectively. Using this type of analysis, EME recorded $1.9 billion impairment of EME's Ferrybridge and Fiddler's Ferry power plants during the third quarter of 2001 and Edison Enterprises recorded $127 million impairment for the majority of its assets in 2001. See "Results of Operations and Historical Cash Flow Analysis—Results of Operations—Earnings (Loss) from Discontinued Operations," for further discussion.

EME operates several power plants under leases as described below under "—Off-Balance Sheet Financing." Under generally accepted accounting principles as currently interpreted, EME is not required to record a loss if future cash flows from use of an asset under lease are less than the expected minimum lease payments. This accounting issue has been discussed in an authoritative accounting interpretation for the recognition by a purchaser of losses on firmly committed executory contracts, without reaching a consensus. Future minimum lease payments on the Collins Station are estimated to be $1.3 billion. As a result, if the accounting guidance in this area were to change, EME could be required to record a loss on this lease, depending on an assessment of future expected cash flow at the time such guidance was changed.

Due to lower wholesale prices for energy during 2002 and 2003 (see "MEHC and EME: Market Risk Exposures—Commodity Price Risk"), EME has suspended operations of four units at the Illinois plants (Units 1 and 2 at Will County and Units 4 and 5 at the Collins Station). EME continues to record depreciation on such assets during the period that EME has suspended operations. Accounting for these units as idle facilities requires management's judgment that these units will return to service. EME has continued the maintenance of these units in order to return them to service when market conditions improve on a sustained basis and future environmental uncertainties are resolved. If market conditions do not improve on a sustained basis, environmental uncertainties are not resolved or are resolved unfavorably, or if a decision is made not to return them to service due to other factors, EME could sell or decommission one or more of these units. Such a decision could result in a loss on sale or a write-down of the carrying value of these assets.

EME evaluates goodwill whenever indicators of impairment exist, but at least annually on October 1 of each year. EME's goodwill is primarily related to the acquisitions of Contact Energy and First Hydro. EME determined through a fair value analysis conducted by third parties that the fair value of the Contact Energy and First Hydro reporting units was in excess of book value. Accordingly, no impairment of the goodwill related to these reporting units was recorded upon adoption of this standard.

Determining the fair value of the reporting unit under the goodwill and other intangible accounting standard is a critical accounting estimate because: (1) it is susceptible to change from period to period since it requires assumptions regarding future revenue and costs of operations and discount rates over an indefinite life, and (2) the impact of recognizing an impairment on EME's consolidated financial position and results of operations would be material. EME has engaged third parties to conduct appraisals of the fair value of the major reporting units with goodwill on October 1, 2003 (the annual impairment testing

date). The fair value of the First Hydro and Contact Energy reporting units set forth in these appraisals exceeded the carry value.

Derivative Financial Instruments and Hedging Activities

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

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

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

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

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

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

Income Taxes

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

As part of the process of preparing its consolidated financial statements, Edison International is required to estimate its income taxes in each of the jurisdictions in which it operates. This process involves estimating actual current tax expense together with assessing temporary differences resulting from differing treatment of items, such as depreciation, for tax and accounting purposes. These differences result in deferred tax assets and liabilities, which are included within Edison International's consolidated balance sheet. Edison International takes certain tax positions it believes are applied in accordance with tax laws. The application of these positions are subject to interpretation and audit by the IRS. As further described in "Other Developments—Federal Income Taxes," the IRS has raised issues in the 1994 to 1996 audit of Edison International's tax returns with respect to certain leveraged leases at Edison Capital and Edison Capital expects the IRS will also challenge several of its other leveraged leases in the audit of years 1997 through 1999. Edison International does not provide for federal income taxes or tax benefits on the undistributed earnings or losses of its international subsidiaries because such earnings are either reinvested indefinitely or would not be subject to additional taxes if repatriated. At December 31, 2003, EME reviewed the undistributed earnings of its international subsidiaries and concluded:

- Its international holding company, MEC B.V., had negative retained earnings under United States generally accepted accounting principles and negative accumulative earnings and profits for federal income tax purposes.

- Distributions of lower tier international subsidiaries to MEC B.V. are either not taxable or could be distributed without additional income taxes.

- MEC B.V. had outstanding indebtedness to domestic subsidiaries of EME totaling $445 million at December 31, 2003 which could be repaid without incurring additional income taxes.

Management continually evaluates its income tax exposures and provides for allowances and/or reserves as deemed necessary.

Off-Balance Sheet Financing

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

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

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

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

Pensions and Postretirement Benefits Other than Pensions

Pension and other postretirement obligations and the related effects on results of operations are calculated using actuarial models. Two critical assumptions, discount rate and expected return on assets, are important elements of plan expense and liability measurement. Additionally, health care cost trend rates are critical assumptions for postretirement heath 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. At the December 31, 2003 measurement date, Edison International used a discount rate of 6.0% for pensions and 6.25% for postretirement benefits other than pensions (PBOP) that represented the market interest rate for high-quality fixed income investments.

To determine the expected long-term rate of return on pension plan assets, current and expected asset allocations are considered, as well as historical and expected returns on plan assets. The expected rate of return on plan assets was 8.5% for pensions and 8.2% for PBOP. A portion of PBOP trusts asset returns are subject to taxation, so the 8.2% figure above is determined on an after-tax basis. Actual returns on the pension plan assets were 27.6%, 7.3% and 10.8% for the one-year, five-year and ten-year periods ended December 31, 2003, respectively. Actual returns on the PBOP plan assets were 26%, 2.2% and 9.1% over these same periods. Accounting principles provide that differences between expected and actual returns are recognized over the average future service of employees.

At December 31, 2003, Edison International's pension plans included $3.0 billion in projected benefit obligation (PBO), $2.6 billion in accumulated benefit obligation (ABO) and $2.9 billion in plan assets. A 1% decrease in the discount rate would increase the PBO by $210 million, and a 1% increase would decrease the PBO by $195 million, with corresponding changes in the ABO. A 1% decrease in the expected rate of return on plan assets would increase pension expense by $22 million.

SCE accounts for about 92% of Edison International's total pension obligation, and 96% of its assets held in trusts, at December 31, 2003. SCE records pension expense equal to the amount funded to the trusts, as calculated using an actuarial method required for rate-making purposes, in which the impact of market volatility on plan assets is recognized in earnings on a more gradual basis. Any difference between pension expense calculated in accordance with rate-making methods and pension expense or income calculated in accordance with accounting standards is accumulated in a regulatory asset or liability, and will, over time, be recovered from or returned to customers. As of December 31, 2003, this cumulative difference amounted to a regulatory liability of $140 million, meaning that the rate-making method has resulted in recognizing $140 million more in expense than the accounting method since implementation of the pension accounting standard in 1987.

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

See "Other Developments—Employee Compensation and Benefit Plans" for information related to Edison International's cash balance pension plan.

At December 31, 2003, Edison International's PBOP plans included $2.2 billion in PBO and $1.4 billion in plan assets. Total expense for these plans was $122 million for 2003. Increasing the health care cost trend rate by one percentage point would increase the accumulated obligation as of December 31, 2003 by $317 million and annual aggregate service and interest costs by $29 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated obligation as of December 31, 2003 by $257 million and annual aggregate service and interest costs by $23 million.

On December 8, 2003, President Bush signed the Medicare Prescription Drug, Improvement and Modernization Act of 2003. The Act authorized a federal subsidy to be provided to plan sponsors for certain prescription drug benefits under Medicare. Edison International has elected to defer accounting for the effects of the Act until the earlier of the issuance of guidance by the Financial Accounting Standards Board on how to account for the Act, or the remeasurement of plan assets and obligations subsequent to January 31, 2004. Accordingly, any measures of the accumulated postretirement benefit obligation or net periodic postretirement benefit expense above do not reflect the effects of the Act on Edison International's plans. Specific authoritative guidance on the accounting for the federal subsidy is pending and that guidance, when issued, could require Edison International to restate previously reported information.

Rate Regulated Enterprises

SCE applies accounting principles for rate-regulated enterprises to the portion of its operations, in which regulators set rates at levels intended to recover the estimated costs of providing service, plus a return on capital. Due to timing and other differences in the collection of revenue, these principles allow an incurred cost that would otherwise be charged to expense by a nonregulated entity to be capitalized as a regulatory asset if it is probable that the cost is recoverable through future rates and conversely allow creation of a regulatory liability for probable future costs collected through rates in advance. SCE's management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as the current regulatory environment, the issuance of rate orders on recovery of the specific incurred cost or a similar incurred cost to SCE or other rate-regulated entities in California, and assurances from the regulator (as well as its primary intervenor groups) that the incurred cost will be treated as an allowable cost (and not challenged) for rate-making purposes. Because current rates include the recovery of existing regulatory assets and settlement of regulatory liabilities, and rates in effect are

expected to allow SCE to earn a reasonable rate of return, management believes that existing regulatory assets and liabilities are probable of recovery. This determination reflects the current political and regulatory climate in California and is subject to change in the future. If future recovery of costs ceases to be probable, all or part of the regulatory assets and liabilities would have to be written off against current period earnings. At December 31, 2003, the Consolidated Balance Sheets included regulatory assets, less regulatory liabilities, of $234 million. Management continually evaluates the anticipated recovery of regulatory assets, liabilities, and revenue subject to refund and provides for allowances and/or reserves as deemed necessary.

SCE applied judgment in the use of the above principles when it: (1) created the $3.6 billion PROACT regulatory asset in the fourth quarter of 2001; (2) restored $480 million (after-tax) of generation-related regulatory assets based on the URG decision in the second quarter of 2002; and (3) established a $61 million regulatory asset related to the impaired Mohave in the fourth quarter of 2002. In all instances, SCE recorded corresponding credits to earnings upon concluding that such incurred costs were probable of recovery in the future. See further discussion in "Results of Operations and Historical Cash Flow Analysis—Results of Operations—Earnings (Loss) from Continuing Operations" and "SCE: Regulatory Matters—Generation and Power Procurement—PROACT Regulatory Asset," "—Utility-Retained Generation," and "—Mohave Generating Station and Related Proceedings" sections.

NEW ACCOUNTING PRINCIPLES

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

In June 2003, clarifying guidance was issued related to derivative instruments and hedging activities. The guidance is related to pricing adjustments in contracts that qualify under the normal purchases and normal sales exception under derivative instrument accounting. This implementation guidance became effective on October 1, 2003. The guidance had no impact on Edison International's consolidated financial statements.

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

Edison International's impacts of adopting this standard were:

- SCE adjusted its nuclear decommissioning obligation to reflect the fair value of decommissioning its nuclear power facilities. SCE also recognized ARO associated with the decommissioning of other coal-fired generation assets. Fair values were determined based on site-specific studies conducted by third-party contractors.

- At December 31, 2002, SCE had accrued $2.3 billion to decommission its nuclear facilities and $12 million to decommission its share of a coal-fired generating plant, under accounting principles in effect at that time. Of these amounts, $298 million to decommission its inactive nuclear facility was recorded in other long-term liabilities, and the remaining $2.0 billion was recorded as a component of the accumulated provision for depreciation and decommissioning on the consolidated balance sheets in the 2002 Annual Report.

- As of January 1, 2003, SCE reversed the $2.3 billion it had previously recorded for decommissioning, recorded the fair value of its AROs of approximately $2.02 billion in the deferred credits and other liabilities section of the balance sheet, and increased its unamortized nuclear investment by $303 million. The cumulative effect of a change in accounting principle from unrecognized accretion expense and adjustments to depreciation, decommissioning and amortization expense recorded to date was a $354 million after-tax gain, which under accounting standards for rate-regulated enterprises was deferred as a regulatory liability, partially offset by a $235 million deferred tax asset, as of January 1, 2003. Accretion expense on the ARO ($128 million) and depreciation expense on the new asset ($15 million) resulting from the application of the new standard in 2003 reduced the regulatory liability, with no impact on earnings. SCE's ARO liability account increased from $2.02 billion to $2.08 billion in 2003, with the $128 million in accretion partially offset by $68 million in expenditures related to the decommissioning of its inactive nuclear facility. As of December 31, 2003, SCE's ARO for its nuclear facilities totaled approximately $2.07 billion and its nuclear decommissioning trust assets had a fair value of $2.5 billion. If the new standard had been in place on January 1, 2002, SCE's ARO as of that date would have been $1.98 billion. If the standard had been applied retroactively for the years ended December 31, 2002 and 2001, it would not have had any effect on SCE's results of operations.

- SCE has collected in rates amounts for the future costs of removal and decommissioning of assets, and has historically recorded these amounts in accumulated provision for depreciation. However, in accordance with recent Securities and Exchange Commission accounting guidance, the amounts accrued in accumulated provision for depreciation for decommissioning and costs of removal were reclassified to regulatory liabilities as of December 31, 2002. The cost of removal amounts collected for assets not legally required to be removed remains in regulatory liabilities as of December 31, 2003. Amounts collected through rates for cost of removal of plant assets not considered to be legal obligations ($2.02 billion at December 31, 2003 and $1.92 billion at December 31, 2002) are included in regulatory liabilities.

- As of January 1, 2003, EME's ARO was approximately $17 million and EME recorded a cumulative effect adjustment that decreased net income by approximately $9 million, net of tax. If the new standard had been applied retroactively in the years ended December 31, 2002 and 2001, it would not have had a material effect on EME's results of operations.

In December 2003, the Financial Accounting Standards Board issued a revision to an accounting Interpretation (originally issued in January 2003), Consolidation of Variable Interest Entities (VIEs). The primary objective of the Interpretation is to provide guidance on the identification of, and financial reporting for, so-called "variable interest entities," where control may be achieved through means other than voting rights. Under the Interpretation, the enterprise that, using a discounted cash flow method, is expected to absorb or receive the majority of a VIE's expected losses or residual returns, or both, must

consolidate the VIE. This Interpretation is effective for special purpose entities, as defined by accounting principles generally accepted in the United States, as of December 31, 2003, and all other entities as of March 31, 2004.

Guidance related to implementation of this Interpretation is evolving. SCE has over 240 long-term power-purchase contracts with independent power producers that own QFs. SCE was required under federal law to sign such contracts, which typically require SCE to purchase 100% of the power produced by these facilities, and the CPUC controls the terms and pricing. Under this accounting Interpretation, SCE could be required to consolidate some or all of the entities that hold these contracts depending on (1) whether these power generators are considered to be VIEs, and (2) whether SCE is considered to be the consolidating entity. These entities are not legally obligated to provide the financial information to SCE, which would be required to determine whether SCE must consolidate these entities. SCE does not know which, if any, of these entities will provide the necessary information. SCE has no investment in, nor obligation to provide support to, these entities other than its requirement to make payment as required by the power-purchase agreements. However, if SCE is required to consolidate these entities, it may be required to recognize losses to the extent of any negative equity. These losses, if any, would not affect SCE's liquidity. EME's interests in certain power generators could also potentially be considered as variable interests. EME's maximum exposure to loss is generally limited to its investment in these entities. EME has 49%–50% ownership in four QF partnerships that have long-term power sales contracts with SCE. EME accounts for these projects using the equity method. If long-term power-purchase contracts are deemed to be variable interests, and due to the related-party nature of this transaction, it is likely that these four QFs could be consolidated by either EME or SCE.

Edison International had originally disclosed that it would adopt the Interpretation as of October 1, 2003. As a result of the December 2003 revision to the Interpretation and uncertainty surrounding its application to long-term power contracts, Edison International delayed implementation for its special purpose entities to December 31, 2003, and for all other entities until March 31, 2004, as allowed under the December revision of the Interpretation. As a result, EME's Brooklyn Navy Yard project, which is a VIE, was not consolidated as previously disclosed. On December 31, 2003, EME agreed to sell its 50% partnership interest in Brooklyn Navy Yard to a third party. Completion of the sale, expected in first quarter 2004, is subject to closing conditions, including obtaining regulatory approval. If the sale is completed prior to March 31, 2004, EME will not be required to consolidate this entity regardless of the results of the power-contract analysis described above. If the sale is not completed by this date, EME could be required to consolidate the Brooklyn Navy Yard project at March 31, 2004, if it is considered to be the consolidating entity. If required, consolidation would result in EME recording a cumulative effect, after-tax loss of approximately $44 million, primarily due to cumulative losses allocated to the other 50% partner in excess of their equity contributions. If this loss were recorded, it would be reversed in a subsequent period if the sale were completed after March 31, 2004.

Edison Capital has concluded that its investments in its affordable housing and wind projects are variable interests in VIEs. Edison Capital also has power-purchase agreements that could potentially be considered to be variable interests. At December 31, 2003, the maximum exposure to loss from Edison Capital's investments is limited to its investment balance and certain guarantees for a total of $424 million, and recapture of tax credits.

Edison International implemented the Interpretation for its special purpose entities as of December 31, 2003. As a result, Edison International deconsolidated three special purpose entities: EIX Trusts I and II; and EME's Mission Capital, L.P. These special purpose entities function as financing entities. The bonds and securities associated with these financing entities are now included in long-term debt on Edison International's consolidated balance sheet and Edison International no longer consolidates the assets and liabilities of these special purpose entities.

Effective July 1, 2003, Edison International adopted a new accounting standard, Amendment of Statement 133 on Derivative Instruments and Hedging Activities. This statement amends and clarifies financial accounting and reporting for derivative instruments and for hedging activities under derivative instrument accounting. The amendment reflects decisions made by accounting authorities in connection with issues raised about the application of the derivative instrument accounting standard. Generally, the provisions of this new standard apply prospectively for contracts entered into or modified after June 30, 2003 and for hedging relationships designated after June 30, 2003. The adoption of this standard had no impact on Edison International's consolidated financial statements.

Effective July 1, 2003, Edison International adopted a new accounting standard, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity, which required issuers to classify certain freestanding financial instruments as liabilities. These freestanding liabilities include mandatorily redeemable financial instruments, obligations to repurchase the issuer's equity shares by transferring assets and certain obligations to issue a variable number of shares. Effective July 1, 2003, Edison International reclassified its company-obligated mandatorily redeemable securities, its other mandatorily redeemable preferred securities and SCE's preferred stock subject to mandatory redemption to the liabilities section of its consolidated balance sheet. These items were previously classified between liabilities and equity. In addition, effective July 1, 2003, dividend payments on these instruments are included in interest expense – net of amounts capitalized on Edison International's consolidated statements of income. Prior period financial statements are not permitted to be restated for these changes. Therefore, upon adoption there was no cumulative impact incurred due to this accounting change.

In May 2003, the Emerging Issues Task Force (EITF) reached a consensus on Determining Whether an Arrangement Contains a Lease, which provides guidance on how to determine whether an arrangement contains a lease that is within the scope of the standard, Accounting for Leases. A lease is defined as an agreement conveying the right to use property, plant, or equipment (land and/or depreciable assets) usually for a stated period of time. The guidance issued by the EITF could affect the classification of a power sales agreement that meets specific criteria, such as a power sales agreement for substantially all of the output from a power plant to one customer. If a power sales agreement meets the guidance issued by the EITF, it would be accounted for as a lease subject to the lease accounting standard. The consensus is effective prospectively for arrangements entered into or modified after June 30, 2003. The consensus had no impact on Edison International's consolidated financial statements.

COMMITMENTS AND GUARANTEES

Edison International's commitments for the years 2004 through 2008 and thereafter are estimated below:

In millions	2004	2005	2006	2007	2008	Thereafter
Long-term debt maturities and sinking fund requirements	$ 2,003	$ 753	$ 1,805	$ 1,764	$ 1,276	$ 6,189
Fuel supply contract payments	911	814	533	377	204	1,579
Gas transportation payments	7	7	7	7	7	65
Purchased-power capacity payments	682	663	637	637	444	3,621
Unconditional purchase obligations	10	10	10	10	10	89
Estimated noncancelable lease payments	334	374	452	487	484	4,577
Preferred securities redemption requirements	9	9	173	69	54	—

Edison International's projected construction expenditures for 2004 are $2.0 billion, including the investment and projected construction expenditures for the Mountainview project (see "Acquisitions and Dispositions"). These expenditures are planned to be financed primarily through cash generated from operations and borrowings.

Fuel Supply Contracts

SCE and EME have fuel supply contracts which require payment only if the fuel is made available for purchase. Certain gas and coal fuel contracts require payment of certain fixed charges whether or not gas or coal is delivered. In addition, fuel supply contract payments include payments for nuclear fuel commitments at SCE.

Gas Transportation

At December 31, 2003, EME had a contractual commitment to transport natural gas. EME is committed to pay minimum fees under this agreement, which has a term of 15 years.

Power-Purchase Contracts

SCE has power-purchase contracts with certain QFs (cogenerators and small power producers) and other utilities. These contracts provide for capacity payments if a facility meets certain performance obligations and energy payments based on actual power supplied to SCE. There are no requirements to make debt-service payments. In an effort to replace higher-cost contract payments with lower-cost replacement power, SCE has entered into settlements to end its contract obligations with certain QFs. The settlements are reported as power-purchase contracts on the balance sheets. In addition, SCE entered into bilateral forward power contracts during 2003, which contain capacity payment provisions.

Unconditional Purchase Obligations

SCE has unconditional purchase obligations for part of a power plant's generating output, as well as firm transmission service from another utility. Minimum payments are based, in part, on the debt-service requirements of the provider, whether or not the plant or transmission line is operable. The purchased-power contract is expected to provide approximately 5% of current or estimated future operating capacity, and is reported as power-purchase contracts (approximately $28 million).

Leases

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

At December 31, 2003, minimum operating lease payments were primarily related to long-term leases for EME's Collins, Powerton, Joliet and Homer City power plants. In connection with the 1999 acquisition of the Illinois plants, EME assigned the right to purchase the Collins gas and oil-fired power plant to third-party lessors. The third-party lessors purchased the Collins Station for $860 million and leased the plant to EME. During 2000, EME entered into sale-leaseback transactions for equipment, primarily the Illinois peaker power units, and for two power facilities, the Powerton and Joliet coal fired stations located in Illinois, with third-party lessors. In August 2002, EME exercised its option and repurchased the Illinois peaker power units. 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. For further discussion, see "Off-Balance Sheet Transactions—EME's Off-Balance Sheet Transactions—Sale-Leaseback Transactions."

Other Commitments

As of December 31, 2003, Edison Capital had outstanding commitments of $68 million to fund energy and infrastructure investments. Prior to funding any commitments, specific contract conditions must be

satisfied. At December 31, 2003, Edison Capital had deposited approximately $5 million as collateral for several letters of credit currently outstanding.

At December 31, 2003, EME had firm commitments to spend approximately $80 million on construction and other capital investments during 2004 through 2006. The construction expenditures primarily relate to the construction of a power plant in New Zealand by Contact Energy. The capital expenditures primarily relate to new plant and equipment at EME's Midwest Generation subsidiary and its Contact Energy project.

At December 31, 2003, EME's 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 ComEd, 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 LLC at prices based primarily on operations and maintenance and fuel costs.

EME Homer City entered into a Coal Cleaning Agreement with Homer City Coal Processing Corporation to operate and maintain a coal cleaning plant owned by EME Homer City. Under the terms of the agreement, EME Homer City is obligated to reimburse Homer City Coal Processing Corporation for the actual costs incurred in the operations and maintenance of the coal cleaning plant, a fixed general and administrative service fee of approximately $260 thousand per year, and an operating fee that ranges from $.20 to $.35 per ton depending on the level of tonnage. The agreement expired on August 31, 2002 and was renewed with the same terms through December 31, 2005, with a two-year extension option.

At December 31, 2003, commitments related to these two contracts discussed above are summarized as follows: 2004 – $11 million; 2005 – $10 million; 2006 – $4 million; 2007 – $4 million; and 2008 – $4 million.

Edison International's expected contributions (all by the employer) for United States pension and PBOP plans are approximately $47 million and $100 million, respectively, for the year ended December 31, 2004. These amounts are subject to change based on, among other things, the limits established for federal tax deductibility (pension plans) and the impact of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (PBOP plans).

EME's Guarantees and Indemnities

Tax Indemnity Agreements

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

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

In connection with the acquisition of the Illinois plants, EME agreed to indemnify ComEd with respect to environmental liabilities before and after the date of sale as specified in the Asset Sale Agreement dated

March 22, 1999. The indemnification claims are reduced by any insurance proceeds and tax benefits related to such claims and are subject to a requirement by ComEd to take 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. The indemnification for the environmental liabilities referred to above is not limited in term and would be triggered by a valid claim from ComEd. Except as discussed below, EME has not recorded a liability related to this indemnity.

Midwest Generation entered into a supplemental agreement with ComEd 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 ComEd 50% of specific existing asbestos claims less recovery of insurance costs, and agreed to a sharing arrangement for liabilities associated with future asbestos related claims as specified in the agreement. The obligations under this agreement are not subject to a maximum liability. The supplemental agreement has a five-year term with an automatic renewal provision (subject to the right to terminate). Payments are made under this indemnity by a valid claim provided from ComEd. At December 31, 2003, Midwest Generation had $10 million recorded as a liability related to this matter and had made $1 million in payments.

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 Generation L.P. (EME Homer City) agreed to indemnify the sellers with respect to environmental liabilities before and after the date of sale as specified in the Asset Purchase Agreement dated August 1, 1998. 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. Payments would be triggered under this indemnity by a claim from the sellers. EME has not recorded a liability related to this indemnity.

Indemnities Provided Under Asset Sale Agreements

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

Guarantee of Brooklyn Navy Yard Contractor Settlement Payments

Brooklyn Navy Yard is a 286 MW gas-fired cogeneration power plant in Brooklyn, New York. EME's wholly owned subsidiary owns 50% of the project. In February 1997, the construction contractor asserted general monetary claims under the turnkey agreement against Brooklyn Navy Yard Cogeneration Partners, L.P. A settlement agreement was executed on January 17, 2003, and all litigation has been dismissed. EME agreed to indemnify Brooklyn Navy Yard Cogeneration Partners, L.P. for any payments due under this settlement agreement, which are scheduled through 2006. At December 31, 2003, EME recorded a liability of $14 million related to this indemnity.

Guarantee of 50% of TM Star Fuel Supply Obligations

TM Star was formed for the limited purpose of selling natural gas to March Point Cogeneration Company, an affiliate through common ownership, under a fuel supply agreement that extends through December 31, 2011. TM Star has entered into fuel purchase contracts with unrelated third parties to meet a portion of the obligations under the fuel supply agreement. EME has guaranteed 50% of TM Star's obligation under the fuel supply agreement to March Point Cogeneration Company. Due to the nature of the obligation under this guarantee, a maximum potential liability cannot be determined. TM Star has met its obligations to March Point Cogeneration Company, and, accordingly, no claims against this guarantee have been made. TM Star was merged into March Point Cogeneration Company effective as of January 16, 2004, and this guarantee terminated by operation of law as of that date.

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 contracts. In addition, subsidiaries of EME have guaranteed the obligations of Kern River Cogeneration Company and Sycamore Cogeneration Company under their project power sales agreements to repay capacity payments to the projects' power purchaser in the event that the projects unilaterally terminate their performance or reduce their electric power producing capability during the term of the power contracts. The obligations under the indemnification agreements as of December 31, 2003, if payment were required, would be $181 million. EME has no reason to believe that any of these projects will either cease operations or reduce its electric power producing capability during the term of its power contract.

Bank Indemnity under a Letter of Credit Supporting ISAB Energy's Debt Service Reserve Account

EME agreed to indemnify its lenders under its credit facilities from amounts drawn on a $26 million letter of credit issued for the benefit of the lenders to ISAB Energy, a 49% unconsolidated affiliate, in lieu of ISAB Energy funding a debt service reserve account using additional equity contributions. Accordingly, a default under ISAB Energy's project debt could result in a draw under the letter of credit which, in turn, would result in a borrowing under EME's credit facilities. The letter of credit is renewed each six-month period or until ISAB Energy funds the debt service account. The indemnification is subject to the maximum amount drawn under the letter of credit. EME has not recorded a liability related to this indemnity.

OFF-BALANCE SHEET TRANSACTIONS

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

EME's Off-Balance Sheet Transactions

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

Investments Accounted for under the Equity Method

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

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

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

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, 2003, entities which EME has accounted for under the equity method had indebtedness of $6 billion, of which $3 billion is proportionate to EME's ownership interest in these projects.

Sale-Leaseback Transactions

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

EME's subsidiaries account for these leases as financings in their separate financial statements due to specific guarantees provided by EME or another one its subsidiaries as part of the sale-leaseback transactions. These guarantees do not preclude EME from recording these transactions as operating leases in its consolidated financial statements, but constitute continuing involvement under the accounting standard that precludes EME's subsidiaries from utilizing this accounting treatment in their separate subsidiary financial statements. Instead, each subsidiary continues to record the power plants as assets in a similar manner to a capital lease and records the obligations under the leases as lease financings. EME's subsidiaries, therefore, record depreciation expense from the power plants and interest expense

from the lease financing in lieu of an operating lease expense which EME uses in preparing its consolidated financial statements. The treatment of these leases as an operating lease in its consolidated financial statements in lieu of a lease financing, which is recorded by EME's subsidiaries, results in an increase in consolidated net income by $81 million, $89 million and $55 million in 2003, 2002 and 2001, respectively.

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

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

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

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

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

The operating lease payments to be made by each of EME's subsidiary lessees are structured to service the lessor debt and provide a return to the owner/lessor's equity investors. Neither the value of the leased assets nor the lessor debt is reflected in EME's consolidated balance sheet. In accordance with generally accepted accounting principles, EME records rent expense on a levelized basis over the terms of the respective leases. To the extent that EME's cash rent payments exceed the amount levelized over the term of each lease, EME records prepaid rent. At December 31, 2003 and 2002, prepaid rent on these leases was $214 million and $117 million, respectively. To the extent that EME's cash rent payments are less than the amount levelized, EME reduces the amount of prepaid rent.

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

obligations under EME's guarantee of the Powerton and Joliet leases. These events could have a material adverse effect on EME's results of operations and financial position.

EME's minimum lease obligations under its power related leases are set forth under "Commitments and Guarantees." Also see "MEHC and EME: Liquidity—Key Financing Developments—EME's Subsidiary Financing Plans—Agreement in Principle to Terminate the Collins Station Lease."

EME's Obligations to Midwest Generation, LLC

The proceeds, in the aggregate amount of approximately $1.4 billion, received by Midwest Generation from the sale of the Powerton and Joliet plants, described above under Sale-Leaseback Transactions, were loaned to EME. EME used the proceeds from this loan to repay corporate indebtedness. Although interest and principal payments made by EME to Midwest Generation under this intercompany loan assist in the payment of the lease rental payments owing by Midwest Generation, the intercompany obligation does not appear on 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	Amount
Years Ending December 31,	
2004	$ 2
2005	2
2006	3
2007	3
2008	4
Thereafter	1,352
Total	$1,366

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

Edison Capital's Off-Balance Sheet Transactions

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

Investments Accounted for under the Equity Method

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

Edison Capital has invested in affordable housing projects utilizing partnership or limited liability companies in which Edison Capital is a limited partner or limited liability member. In these entities, Edison Capital usually owns a 99% interest. With a few exceptions, an unrelated general partner or managing member exercises operating control; voting rights of Edison Capital are limited by agreement

to certain 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, 2003, Edison Capital had made guarantees to lenders in the amount of $5 million.

At December 31, 2003, entities that Edison Capital has accounted for under the equity method had indebtedness of $1.7 billion, of which approximately $474 million is proportionate to Edison Capital's ownership interest in these projects. Substantially all of this debt is nonrecourse to Edison Capital.

Leveraged Leases

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

At December 31, 2003, Edison Capital had investments of $2.4 billion in its leveraged leases, with nonrecourse debt in the amount of $5 billion.

OTHER DEVELOPMENTS

Environmental Matters

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.

Environmental Remediation

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

Edison International's recorded estimated minimum liability to remediate its 32 identified sites at SCE (26 sites) and EME (6 sites related to Midwest Generation) is $94 million, $92 million of which is related to SCE. In third quarter 2003, SCE sold certain oil storage and pipeline facilities. This sale caused a reduction in Edison International's recorded estimated minimum environmental liability. 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 $238 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.

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 $71 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 $13 million to $25 million. Recorded costs for 2003 were $14 million.

Based on currently available information, Edison International believes it is unlikely that it will incur amounts in excess of the upper limit of the estimated range for 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.

Clean Air Act

The Clean Air Act requires power producers to have emissions allowances to emit sulfur dioxide. Power companies receive emissions allowances from the federal government and may bank or sell excess allowances. SCE expects to have excess allowances under Phase II of the Clean Air Act (2000 and later).

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

SCE's share of the costs of complying with the consent decree and taking other actions to continue operation of Mohave beyond 2005 is estimated to be approximately $605 million. SCE has received from the State of Nevada a permit to install the necessary pollution-control equipment. However, SCE has suspended its efforts to seek CPUC approval to install the Mohave pollution-control equipment because it has not obtained reasonable assurance of adequate coal and water supplies for operating Mohave beyond 2005. Unless adequate coal and water supplies are obtained, it will become necessary to shut down

Mohave after December 31, 2005. If the station is shut down at that time, the shutdown is not expected to have a material adverse impact on SCE's financial position or results of operations, assuming the remaining book value of the station (approximately $24 million as of December 31, 2003) and the related regulatory asset (approximately $66 million as of December 31, 2003), and plant closure and decommissioning-related costs are recoverable in future rates. SCE cannot predict with certainty what effect any future actions by the CPUC may have on this matter. See "SCE: Regulatory Matters—Generation and Power Procurement—Mohave Generating Station and Related Proceedings" for further discussion of the Mohave issues.

Edison International's facilities in the United States are subject to the Clean Air Act's new source review (NSR) requirements related to modifications of air emissions sources at electric generating stations. Over the past five years, the United States Environmental Protection Agency (EPA) has initiated investigations of numerous electric utilities seeking to determine whether these utilities engaged in activities in violation of the NSR requirements, brought enforcement actions against some of those utilities, and reached settlements with some of those utilities. EPA has made information requests concerning electric generating stations in which SCE and EME hold ownership interests, including SCE's Four Corners station and EME's Midwest Generation and Homer City stations. Other than these requests for information, no enforcement-related proceedings have been initiated against any Edison International facilities by EPA relating to NSR compliance.

Over this same period, EPA has proposed several regulatory changes to NSR requirements that would clarify and provide greater guidance to the utility industry as to what activities can be undertaken without triggering the NSR requirements. Several of these regulatory changes have been challenged in the courts. As a result of these developments, EPA's enforcement policy on alleged NSR violations is currently uncertain.

These developments will continue to be monitored by Edison International, SCE, and EME, 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 are $2.3 billion, including the $605 million for Mohave discussed above for the 2004–2008 period, mainly for undergrounding certain transmission and distribution lines at SCE and upgrading environmental controls at EME.

Employee Compensation and Benefit Plans

On July 31, 2003, a federal district court held that the formula used in a cash balance pension plan created by International Business Machine Corporation (IBM) in 1999 violated the age discrimination provisions of the Employee Retirement Income Security Act of 1974. In its decision, the federal district court set forth a standard for cash balance pension plans. This decision, however, conflicts with the decisions from two other federal district courts and with the proposed regulations for cash balance pension plans issued by the IRS in December 2002. On February 12, 2004, the same federal district court ruled that IBM must make back payments to workers covered under this plan. IBM has indicated that it will appeal both decisions to the United States Court of Appeals for the Seventh Circuit. The formula for Edison International's cash balance pension plan does not meet the standard set forth in the federal district court's July 31, 2003 decision. Edison International cannot predict with certainty the effect of the two IBM decisions on Edison International's cash balance pension plan.

Federal Income Taxes

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

Among the issues raised by the IRS in the 1994 to 1996 audit was Edison Capital's treatment of the EPZ and Dutch electric locomotive leases. Written protests were filed against these deficiency notices, as well as other alleged deficiencies, asserting that the IRS's position misstates material facts, misapplies the law and is incorrect. This matter is now being considered by the Administrative Appeals branch of the IRS. Edison Capital will contest the assessment through administrative appeals and litigation, if necessary, and believes it should prevail in an outcome that will not have a material adverse financial impact.

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

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

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

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

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

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

Thomas M. Noonan
Vice President
and Controller

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

March 10, 2004

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, 2003 and 2002, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion. The financial statements of the Company for the year ended December 31, 2001 were audited by other independent accountants who have ceased operations. Those independent accountants expressed an unqualified opinion on the financial statements and included an explanatory paragraph that described the change in manner in which the Company accounts for derivative instruments and hedging activities and the impairment of long-lived assets discussed in Note 1 to the financial statements in their report dated March 25, 2002.

As discussed in Note 1 to the consolidated financial statements, the Company changed the manner in which it accounts for asset retirement costs as of January 1, 2003, financial instruments with characteristics of both debt and equity as of July 1, 2003, and certain variable interest entities as of December 31, 2003.

PricewaterhouseCoopers LLP

Los Angeles, California
March 10, 2004

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

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

We have audited the accompanying consolidated balance sheets of Edison International (a California corporation) and its subsidiaries as of December 31, 2001, and 2000, and the related consolidated statements of income (loss), comprehensive income (loss), cash flows and common shareholders' equity for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of Edison International's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Edison International and its subsidiaries as of December 31, 2001, and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

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

Arthur Andersen LLP

Los Angeles, California
March 25, 2002

In millions, except per-share amounts Year ended December 31,	2003	2002	2001
Electric utility	$ 8,853	$ 8,705	$ 8,120
Nonutility power generation	3,181	2,750	2,594
Financial services and other	101	33	348
Total operating revenue	12,135	11,488	11,062
Fuel	1,338	1,186	1,128
Purchased power	2,786	2,016	3,770
Provisions for regulatory adjustment clauses – net	1,138	1,502	(3,028)
Other operation and maintenance	3,389	3,156	3,029
Asset impairment	304	86	—
Depreciation, decommissioning and amortization	1,184	1,030	973
Property and other taxes	210	145	114
Net gain on sale of utility plant	(5)	(5)	(6)
Total operating expenses	10,344	9,116	5,980
Operating income	1,791	2,372	5,082
Interest and dividend income	127	287	282
Equity in income from partnerships and unconsolidated subsidiaries – net	354	249	343
Other nonoperating income	91	90	108
Interest expense – net of amounts capitalized	(1,226)	(1,283)	(1,582)
Other nonoperating deductions	(84)	(74)	(70)
Dividends on preferred securities	(51)	(96)	(92)
Dividends on utility preferred stock	(10)	(19)	(22)
Income from continuing operations before tax	992	1,526	4,049
Income tax	213	391	1,647
Income from continuing operations	779	1,135	2,402
Income (loss) from discontinued operations (including gain on disposal of $44 in 2003 and loss on disposal of $1,309 in 2001) – net of tax	51	(58)	(1,367)
Income before accounting change	830	1,077	1,035
Cumulative effect of accounting change – net of tax	(9)	—	—
Net income	$ 821	$ 1,077	$ 1,035
Weighted-average shares of common stock outstanding	326	326	326
Basic earnings (loss) per share:			
Continuing operations	$ 2.39	$ 3.49	$ 7.37
Discontinued operations	0.16	(0.18)	(4.19)
Cumulative effect of accounting change	(0.03)	—	—
Total	$ 2.52	$ 3.31	$ 3.18
Weighted-average shares, including effect of dilutive securities	329	328	326
Diluted earnings (loss) per share:			
Continuing operations	$ 2.37	$ 3.46	$ 7.36
Discontinued operations	0.16	(0.18)	(4.19)
Cumulative effect of accounting change	(0.03)	—	—
Total	$ 2.50	$ 3.28	$ 3.17
Dividends declared per common share	$ 0.20	$ —	$ —

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

Consolidated Statements of Comprehensive Income **Edison International**

In millions Year ended December 31,	2003	2002	2001
Net income	$ 821	$1,077	$1,035
Other comprehensive income (expense), net of tax:			
Foreign currency translation adjustments	154	125	6
Minimum pension liability adjustment	(2)	(21)	—
Unrealized gain (loss) on investments – net	2	(9)	—
Unrealized gains (losses) on cash flow hedges:			
Cumulative effect of change in accounting for derivatives	—	6	148
Other unrealized gain (loss) on cash flow hedges – net	50	(20)	(359)
Reclassification adjustment for gain (loss) included in net income	(10)	—	16
Other comprehensive income (expense)	194	81	(189)
Comprehensive income	$1,015	$1,158	$ 846

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

Consolidated Balance Sheets

In millions December 31,	2003	2002
ASSETS		
Cash and equivalents	$ 2,198	$ 2,468
Restricted cash	79	53
Receivables, less allowances of $37 and $49 for uncollectible accounts at respective dates	1,200	1,111
Accrued unbilled revenue	408	437
Fuel inventory	92	124
Materials and supplies, at average cost	252	219
Accumulated deferred income taxes – net	508	527
Trading and price risk management assets	48	34
Regulatory assets – net	—	459
Prepayments	88	85
Other current assets	176	142
Total current assets	5,049	5,659
Nonutility property – less accumulated provision for depreciation of $1,318 and $911 at respective dates	7,701	6,873
Nuclear decommissioning trusts	2,530	2,210
Investments in partnerships and unconsolidated subsidiaries	1,908	2,011
Investments in leveraged leases	2,361	2,313
Other investments	176	256
Total investments and other assets	14,676	13,663
Utility plant, at original cost		
Transmission and distribution	14,861	14,202
Generation	1,371	1,348
Accumulated provision for depreciation	(4,386)	(4,057)
Construction work in progress	600	529
Nuclear fuel, at amortized cost	141	153
Total utility plant	12,587	12,175
Goodwill	868	661
Restricted cash	339	412
Regulatory assets – net	510	—
Other deferred charges	917	914
Total deferred charges	2,634	1,987
Assets of discontinued operations	16	123
Total assets	$ 34,962	$ 33,607

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

In millions, except share amounts December 31,	2003	2002
LIABILITIES AND SHAREHOLDERS' EQUITY		
Short-term debt	$ 252	$ 78
Long-term debt due within one year	2,003	2,761
Preferred stock to be redeemed within one year	9	9
Accounts payable	1,086	786
Accrued taxes	596	855
Trading and risk management liabilities	168	45
Regulatory liabilities – net	276	—
Other current liabilities	1,777	2,070
Total current liabilities	6,167	6,604
Long-term debt	11,787	11,578
Accumulated deferred income taxes – net	5,967	6,099
Accumulated deferred investment tax credits	149	167
Customer advances and other deferred credits	1,554	1,486
Power-purchase contracts	213	309
Other preferred securities subject to mandatory redemption	305	—
Accumulated provision for pensions and benefits	425	461
Asset retirement obligations	2,106	—
Regulatory liabilities – net	—	393
Other long-term liabilities	247	218
Total deferred credits and other liabilities	10,966	9,133
Liabilities of discontinued operations	13	72
Total liabilities	28,933	27,387
Commitments and contingencies (Notes 2, 9 and 10)		
Minority interest	517	425
Preferred stock of utility:		
Not subject to mandatory redemption	129	129
Subject to mandatory redemption	—	147
Company-obligated mandatorily redeemable securities of subsidiaries holding solely parent company debentures	—	951
Other preferred securities	—	131
Total preferred securities of subsidiaries	129	1,358
Common stock (325,811,206 shares outstanding at each date)	1,970	1,973
Accumulated other comprehensive loss	(53)	(247)
Retained earnings	3,466	2,711
Total common shareholders' equity	5,383	4,437
Total liabilities and shareholders' equity	$ 34,962	$ 33,607

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

Consolidated Statements of Cash Flows			Edison International
In millions Year ended December 31,	2003	2002	2001
Cash flows from operating activities:			
Income from continuing operations, after accounting change, net of tax	$ 770	$ 1,135	$ 2,402
Adjustments to reconcile to net cash provided by operating activities:			
Cumulative effect of accounting change – net of tax	9	—	—
Depreciation, decommissioning and amortization	1,184	1,030	973
Other amortization	108	113	92
Deferred income taxes and investment tax credits	194	160	1,908
Equity in income from partnerships and unconsolidated subsidiaries	(354)	(249)	(343)
Income from leveraged leases	(82)	(6)	(154)
Regulatory assets – long-term – net	495	1,860	(3,135)
Gas options	75	14	(91)
Asset impairment	304	86	—
Write-down of nonutility assets	—	—	245
Levelized rent expense	(96)	—	—
Other assets	134	3	(51)
Other liabilities	(347)	170	(134)
Changes in working capital:			
Receivables and accrued unbilled revenue	(160)	193	(47)
Regulatory assets – short-term – net	697	(376)	(278)
Fuel inventory, materials and supplies	4	(11)	(16)
Prepayments and other current assets	86	(17)	203
Accrued interest and taxes	(120)	523	(240)
Accounts payable and other current liabilities	42	(2,724)	1,551
Distributions and dividends from unconsolidated entities	416	337	236
Operating cash flows from discontinued operations	(52)	80	(147)
Net cash provided by operating activities	3,307	2,321	2,974
Cash flows from financing activities:			
Long-term debt issued	1,058	409	3,386
Long-term debt repaid	(2,796)	(1,784)	(1,761)
Bonds remarketed (repurchased) and funds held in trust – net	—	191	(130)
Issuance of preferred securities	—	—	104
Redemption of preferred securities	(6)	(100)	(164)
Rate reduction notes repaid	(246)	(246)	(246)
Nuclear fuel financing – net	—	(59)	(21)
Short-term debt financing – net	26	(956)	(1,547)
Dividends to minority shareholders	(42)	(37)	—
Financing cash flows from discontinued operations	—	(19)	(1,178)
Net cash used by financing activities	(2,006)	(2,601)	(1,557)
Cash flows from investing activities:			
Additions to property and plant – net	(1,288)	(1,590)	(933)
Purchase of power sales agreement	—	(80)	—
Purchase of common stock of acquired companies	(278)	—	—
Proceeds from sale of property	7	62	1,032
Proceeds from sale of interest in projects	41	—	—
Contributions to nuclear decommissioning trusts – net	(86)	(12)	(36)
Distributions from (investments in) partnerships and unconsolidated subsidiaries	(63)	42	(122)
Net investments in leveraged leases	—	—	68
Other assets	(58)	247	(433)
Investing cash flows from discontinued operations	150	2	1,125
Net cash provided (used) by investing activities	(1,575)	(1,329)	701
Effect of exchange rate changes on cash	4	23	(37)
Net increase (decrease) in cash and equivalents	(270)	(1,586)	2,081
Cash and equivalents, beginning of year	2,468	4,054	1,973
Cash and equivalents, end of year	2,198	2,468	4,054
Cash and equivalents – discontinued operations	—	—	(63)
Cash and equivalents – continuing operations	$ 2,198	$ 2,468	$ 3,991

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

In millions	Common Stock	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Common Shareholders' Equity
Balance at December 31, 2000	$ 1,960	$ (139)	$ 599	$ 2,420
Net income			1,035	1,035
Foreign currency translation adjustments		(1)		(1)
Tax effect		7		7
Other unrealized loss on cash flow hedges		(296)		(296)
Tax effect		(63)		(63)
Reclassification adjustment for gain included in net income		24		24
Tax effect		(8)		(8)
Cumulative effect of change in accounting for derivatives		24		24
Tax effect		124		124
Stock option appreciation	6			6
Balance at December 31, 2001	$ 1,966	$ (328)	$ 1,634	$ 3,272
Net income			1,077	1,077
Foreign currency translation adjustments		128		128
Tax effect		(3)		(3)
Minimum pension liability adjustment		(29)		(29)
Tax effect		8		8
Unrealized loss on investment		(14)		(14)
Tax effect		5		5
Other unrealized loss on cash flow hedges		(22)		(22)
Tax effect		2		2
Cumulative effect of change in accounting for derivatives		12		12
Tax effect		(6)		(6)
Stock option appreciation and other	7			7
Balance at December 31, 2002	$ 1,973	$ (247)	$ 2,711	$ 4,437
Net income			821	821
Foreign currency translation adjustments		159		159
Tax effect		(5)		(5)
Minimum pension liability adjustment		(3)		(3)
Tax effect		1		1
Unrealized gain on investment		3		3
Tax effect		(1)		(1)
Other unrealized gain on cash flow hedges		54		54
Tax effect		(4)		(4)
Reclassification adjustment for loss included in net income		(9)		(9)
Tax effect		(1)		(1)
Dividends declared on common stock			(65)	(65)
Stock option appreciation and other	(3)		(1)	(4)
Balance at December 31, 2003	$ 1,970	$ (53)	$ 3,466	$ 5,383

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

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

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

Note 1. Summary of Significant Accounting Policies

Edison International's principal wholly owned subsidiaries include: Southern California Edison Company (SCE), a rate-regulated electric utility that supplies electric energy to a 50,000 square-mile area of central, coastal and southern California; Edison Mission Energy (EME), a producer of electricity engaged in the development and operation of electric power generation facilities worldwide; Edison Capital, a provider of capital and financial services; and Mission Energy Holding Company (MEHC), a holding company for EME. EME and Edison Capital have domestic and foreign projects, primarily in Europe, Asia, Australia and Africa.

EME's plants are located in different geographic areas, partially mitigating the effects of regional markets, economic downturns or unusual weather conditions. EME's domestic facilities (other than Homer City and the Illinois plants) generally sell power to a limited number of electric utilities under long-term (15 years to 30 years) contracts. A plant in Australia sells its energy and capacity production through a centralized power pool. A plant in the United Kingdom sells its energy production by entering into physical bilateral contracts with various counterparties. Other electric power generated overseas is sold under short- and long-term contracts to electricity companies, electricity buying groups or electric utilities located in the country where the power is generated. EME also conducts energy trading and price risk management activities for its generation in power markets open to competition.

Basis of Presentation

The consolidated financial statements include Edison International and its wholly owned subsidiaries. Edison International's subsidiaries consolidate their majority owned subsidiaries. In addition, Edison International's subsidiaries generally use the equity method to account for significant investments in partnerships and subsidiaries in which they own 50% or less of the significant voting rights. However, beginning October 1, 2003, Edison Capital began consolidating its Storm Lake project due to taking temporary control of the project company. Effective December 31, 2003, Edison International no longer consolidates the assets and liabilities of three special purpose entities, EIX Trusts I and II (which are Delaware business trusts), and Mission Capital, L.P. See further discussion in "New Accounting Principles." Intercompany transactions have been eliminated, except EME's profits from energy sales to SCE, which are allowed in utility rates. Except as indicated, amounts presented in the Notes to the Consolidated Financial Statements relate to continuing operations.

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

Financial statements prepared in compliance with accounting principles generally accepted in the United States require management to make estimates and assumptions that affect the amounts reported in the financial statements and Notes. Actual results could differ from those estimates. Certain significant estimates related to electric utility regulatory matters, financial instruments, income taxes, pensions and postretirement benefits other than pensions, decommissioning and contingencies are further discussed in Notes 2, 3, 6, 7, 9 and 10 to the Consolidated Financial Statements, respectively.

Cash Equivalents

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

Debt and Equity Investments

Net unrealized gains (losses) on equity investments are recorded as a separate component of shareholders' equity under the caption "Accumulated other comprehensive income." Unrealized gains and losses on decommissioning trust funds increase or decrease the related regulatory asset or liability. All investments are classified as available-for-sale.

Earnings (Loss) Per Share (EPS)

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

The following table presents the effect of dilutive securities on the number of weighted-average shares of common stock outstanding:

In millions Year ended December 31,	2003	2002	2001
Basic weighted-average shares of common stock outstanding	326	326	326
Stock-based compensation awards exercisable	3	2	—
Dilutive weighted-average shares of common stock outstanding	329	328	326

Fuel Inventory

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

Goodwill

Goodwill represents the excess of cost incurred over the fair value of net assets acquired in a purchase transaction. Goodwill was amortized on a straight-line basis over periods ranging from 20 to 40 years. On January 1, 2002, the amortization of goodwill ceased upon adoption of a new accounting standard. As required by this new accounting standard, EME evaluates goodwill whenever indicators of impairment exist, but at least annually on October 1 of each year. EME's goodwill ($867 million at December 31, 2003 and $660 million at December 31, 2002) is primarily related to the acquisitions of Contact Energy and First Hydro. In 2003, EME determined through a fair value analysis conducted by third parties that the fair value of the Contact Energy and First Hydro reporting units was in excess of book value. Accordingly, no adjustment to impair goodwill was necessary at December 31, 2003.

New Accounting Principles

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

In June 2003, clarifying guidance was issued related to derivative instruments and hedging activities. The guidance is related to pricing adjustments in contracts that qualify under the normal purchases and normal sales exception under derivative instrument accounting. This implementation guidance became effective on October 1, 2003. The guidance had no impact on Edison International's consolidated financial statements.

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

Edison International's impacts of adopting this standard were:

- SCE adjusted its nuclear decommissioning obligation to reflect the fair value of decommissioning its nuclear power facilities. SCE also recognized AROs associated with the decommissioning of other coal-fired generation assets. Fair values were determined based on site-specific studies conducted by third-party contractors.

- At December 31, 2002, SCE had accrued $2.3 billion to decommission its nuclear facilities and $12 million to decommission its share of a coal-fired generating plant, under accounting principles in effect at that time. Of these amounts, $298 million to decommission its inactive nuclear facility was recorded in other long-term liabilities, and the remaining $2.0 billion was recorded as a component of the accumulated provision for depreciation and decommissioning on the consolidated balance sheets in the 2002 Annual Report.

- As of January 1, 2003, SCE reversed the $2.3 billion it had previously recorded for decommissioning, recorded the fair value of its AROs of approximately $2.02 billion in the deferred credits and other liabilities section of the balance sheet, and increased its unamortized nuclear investment by $303 million. The cumulative effect of a change in accounting principle from unrecognized accretion expense and adjustments to depreciation, decommissioning and amortization expense recorded to date was a $354 million after-tax gain, which under accounting standards for rate-regulated enterprises was deferred as a regulatory liability, partially offset by a $235 million deferred tax asset, as of January 1, 2003. Accretion expense on the ARO ($128 million) and depreciation expense on the new asset

($15 million) resulting from the application of the new standard in 2003 reduced the regulatory liability, with no impact on earnings. SCE's ARO liability account increased from $2.02 billion to $2.08 billion in 2003, with the $128 million in accretion partially offset by $68 million in expenditures related to the decommissioning of its inactive nuclear facility. As of December 31, 2003, SCE's ARO for its nuclear facilities totaled approximately $2.07 billion and its nuclear decommissioning trust assets had a fair value of $2.5 billion. If the new standard had been in place on January 1, 2002, SCE's ARO as of that date would have been $1.98 billion. If the standard had been applied retroactively for the years ended December 31, 2002 and 2001, it would not have had any effect on SCE's results of operations.

- SCE has collected in rates amounts for the future costs of removal and decommissioning of assets, and has historically recorded these amounts in accumulated provision for depreciation. However, in accordance with recent Securities and Exchange Commission accounting guidance, the amounts accrued in accumulated provision for depreciation for decommissioning and costs of removal were reclassified to regulatory liabilities as of December 31, 2002. The cost of removal amounts collected for assets not legally required to be removed remain in regulatory liabilities as of December 31, 2003. Amounts collected through rates for cost of removal of plant assets not considered to be legal obligations ($2.02 billion at December 31, 2003 and $1.92 billion at December 31, 2002) are included in regulatory liabilities.

- As of January 1, 2003, EME's ARO was approximately $17 million and EME recorded a cumulative effect adjustment that decreased net income by approximately $9 million, net of tax. If the new standard had been applied retroactively in the years ended December 31, 2002 and 2001, it would not have had a material effect on EME's results of operations.

In December 2003, the Financial Accounting Standards Board issued a revision to an accounting Interpretation (originally issued in January 2003), Consolidation of Variable Interest Entities (VIEs). The primary objective of the Interpretation is to provide guidance on the identification of, and financial reporting for, so-called "variable interest entities," where control may be achieved through means other than voting rights. Under the Interpretation, the enterprise that, using a discounted cash flow method, is expected to absorb or receive the majority of a VIE's expected losses or residual returns, or both, must consolidate the VIE. This Interpretation is effective for special purpose entities, as defined by accounting principles generally accepted in the United States, as of December 31, 2003, and all other entities as of March 31, 2004.

Guidance related to implementation of this Interpretation is evolving. SCE has over 240 long-term power-purchase contracts with independent power producers that own qualifying facilities (QFs). SCE was required under federal law to sign such contracts, which typically require SCE to purchase 100% of the power produced by these facilities, and the CPUC controls the terms and pricing. Under this accounting Interpretation, SCE could be required to consolidate some or all of the entities that hold these contracts depending on (1) whether these power generators are considered to be VIEs, and (2) whether SCE is considered to be the consolidating entity. These entities are not legally obligated to provide the financial information to SCE, which would be required to determine whether SCE must consolidate these entities. SCE does not know which, if any, of these entities will provide the necessary information. SCE has no investment in, nor obligation to provide support to, these entities other than its requirement to make payment as required by the power purchase agreements. However, if SCE is required to consolidate these entities, it may be required to recognize losses to the extent of any negative equity. These losses, if any, would not affect SCE's liquidity. EME's interests in certain power generators could also potentially be considered as variable interests. EME's maximum exposure to loss is generally limited to its investment in these entities. EME has 49% to 50% ownership in four QF partnerships that have long-term power sales contracts with SCE. EME accounts for these projects using the equity method. If long-term power-purchase contracts are deemed to be variable interests, and due to the related-party nature of this transaction, it is likely that these four QFs could be consolidated by either EME or SCE.

Edison International had originally disclosed that it would adopt the Interpretation as of October 1, 2003. As a result of the December 2003 revision to the Interpretation and uncertainty surrounding its application to long-term power contracts, Edison International delayed implementation for its special purpose entities to December 31, 2003, and for all other entities until March 31, 2004, as allowed under the December revision of the Interpretation. As a result, EME's Brooklyn Navy Yard project, which is a VIE, was not consolidated as previously disclosed. On December 31, 2003, EME agreed to sell its 50% partnership interest in Brooklyn Navy Yard to a third party. Completion of the sale, expected in first quarter 2004, is subject to closing conditions, including obtaining regulatory approval. If the sale is completed prior to March 31, 2004, EME will not be required to consolidate this entity regardless of the results of the power-contract analysis described above. If the sale is not completed by this date, EME could be required to consolidate the Brooklyn Navy Yard project at March 31, 2004, if it is considered to be the consolidating entity. If required, consolidation would result in EME recording a cumulative-effect, after-tax loss of approximately $44 million, primarily due to cumulative losses allocated to the other 50% partner in excess of their equity contributions. If this loss were recorded, it would be reversed in a subsequent period if the sale were completed after March 31, 2004.

Edison Capital has concluded that its investments in its affordable housing and wind projects are variable interests in VIEs. Edison Capital also has power-purchase agreements that could potentially be considered to be variable interests. At December 31, 2003, the maximum exposure to loss from Edison Capital's investments is limited to its investment balance and certain guarantees for a total of $424 million, and recapture of tax credits.

Edison International implemented the Interpretation for its special purpose entities as of December 31, 2003. As a result, Edison International deconsolidated three special purpose entities: EIX Trusts I and II; and EME's Mission Capital, L.P. These special purpose entities function as financing entities. The bonds and securities associated with these financing entities are now included in long-term debt on Edison International's consolidated balance sheet and Edison International no longer consolidates the assets and liabilities of these special purpose entities.

Effective July 1, 2003, Edison International adopted a new accounting standard, Amendment of Statement 133 on Derivative Instruments and Hedging Activities. This statement amends and clarifies financial accounting and reporting for derivative instruments and for hedging activities under derivative instrument accounting. The amendment reflects decisions made by accounting authorities in connection with issues raised about the application of the derivative instrument accounting standard. Generally, the provisions of this new standard apply prospectively for contracts entered into or modified after June 30, 2003 and for hedging relationships designated after June 30, 2003. The adoption of this standard had no impact on Edison International's consolidated financial statements.

Effective July 1, 2003, Edison International adopted a new accounting standard, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity, which required issuers to classify certain freestanding financial instruments as liabilities. These freestanding liabilities include mandatorily redeemable financial instruments, obligations to repurchase the issuer's equity shares by transferring assets and certain obligations to issue a variable number of shares. Effective July 1, 2003, Edison International reclassified its company-obligated mandatorily redeemable securities, its other mandatorily redeemable preferred securities and SCE's preferred stock subject to mandatory redemption to the liabilities section of its consolidated balance sheet. These items were previously classified between liabilities and equity. In addition, effective July 1, 2003, dividend payments on these instruments are included in interest expense – net of amounts capitalized on Edison International's consolidated statements of income. Prior period financial statements are not permitted to be restated for these changes. Therefore, upon adoption there was no cumulative impact incurred due to this accounting change. See disclosures regarding these preferred securities in Note 4.

In May 2003, the Emerging Issues Task Force (EITF) reached a consensus on Determining Whether an Arrangement Contains a Lease, which provides guidance on how to determine whether an arrangement contains a lease that is within the scope of the standard, Accounting for Leases. A lease is defined as an agreement conveying the right to use property, plant, or equipment (land and/or depreciable assets) usually for a stated period of time. The guidance issued by the EITF could affect the classification of a power sales agreement that meets specific criteria, such as a power sales agreement for substantially all of the output from a power plant to one customer. If a power sales agreement meets the guidance issued by the EITF, it would be accounted for as a lease subject to the lease accounting standard. The consensus is effective prospectively for arrangements entered into or modified after June 30, 2003. The consensus had no impact on Edison International's consolidated financial statements.

Nuclear

SCE's nuclear plant investments are recorded as a regulatory asset on its balance sheets. This classification does not affect the rate-making treatment for these assets. SCE had been recovering its investments in San Onofre Nuclear Generating Station (San Onofre) Units 2 and 3 and Palo Verde Nuclear Generating Station (Palo Verde) on an accelerated basis, as authorized by the CPUC. The accelerated recovery was to continue through December 2001, earning a 7.35% fixed rate of return on investment. San Onofre's operating costs, including nuclear fuel and nuclear fuel financing costs, and incremental capital expenditures, were recovered through an incentive pricing plan that allows SCE to receive about 4¢ per kilowatt-hour (kWh) through 2003. Any differences between these costs and the incentive price would flow through to shareholders. Palo Verde's accelerated plant recovery, as well as operating costs, including nuclear fuel and nuclear fuel financing costs, and incremental capital expenditures, were subject to balancing account treatment through the effective date of the 2003 general rate case.

The nuclear rate-making plans were to continue for rate-making purposes at least through the 2003 general rate case effective date for Palo Verde operating costs and through 2003 for the San Onofre incentive pricing plan. However, due to the various unresolved regulatory and legislative issues as of December 31, 2000, SCE was no longer able to conclude that the unamortized nuclear investment was probable of recovery through the rate-making process. As a result, this balance was written off as a charge to earnings at that time. As a result of the CPUC's April 4, 2002 decision that returned SCE's URG assets to cost-based ratemaking, SCE reestablished for financial reporting purposes its unamortized nuclear investment and related flow-through taxes, retroactive to August 31, 2001, based on a 10-year recovery period, effective January 1, 2001, with a corresponding credit to earnings. SCE adjusted the procurement-related obligations account (PROACT) regulatory asset balance to reflect recovery of the nuclear investment in accordance with the final URG decision.

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

Other Nonoperating Income and Deductions

Other nonoperating income and deductions are as follows:

In millions Year ended December 31,	2003	2002	2001
Nonutility nonoperating income	$ 19	$ 15	$ 51
Utility nonoperating income	72	75	57
Total nonoperating income	$ 91	$ 90	$ 108
Nonutility nonoperating deductions	$ 43	$ 83	$ 32
Utility nonoperating deductions	41	(9)	38
Total nonoperating deductions	$ 84	$ 74	$ 70

Planned Major Maintenance

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

Property and Plant

Utility plant additions, including replacements and betterments, are capitalized. Such costs include direct material and labor, construction overhead and an allowance for funds used during construction (AFUDC). AFUDC represents the estimated cost of debt and equity funds that finance utility-plant construction. AFUDC is capitalized during plant construction and reported in current earnings in other nonoperating income. AFUDC is recovered in rates through depreciation expense over the useful life of the related asset. Depreciation of utility plant is computed on a straight-line, remaining-life basis.

Depreciation expense stated as a percent of average original cost of depreciable utility plant was 4.3% for 2003, 4.2% for 2002 and 3.6% for 2001.

AFUDC – equity was $21 million in 2003, $11 million in 2002 and $7 million in 2001. AFUDC – debt was $6 million in 2003, $8 million in 2002 and $9 million in 2001.

Replaced or retired property costs are charged to the accumulated provision for depreciation. Historically, cash payments for removal costs less salvage were charged to the accumulated provision for depreciation and decommissioning and cash collections from customers for future decommissioning were credited to accumulated provision for depreciation and decommissioning. However, as a result of recent guidance from the staff of the Securities and Exchange Commission, SCE reclassified amounts related to removal costs to regulatory liabilities in its December 31, 2003 and 2002 balance sheets. See further discussion in "New Accounting Principles" and "Regulatory Assets and Liabilities."

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

Generation plant	38 years to 81 years
Distribution plant	24 years to 53 years
Transmission plant	40 years to 60 years
Other plant	5 years to 40 years

SCE's net investment in generation-related utility plant was $867 million at December 31, 2003 and $842 million at December 31, 2002.

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

Nonutility property, including leasehold improvements and construction in progress, is capitalized at cost, including interest incurred on borrowed funds that finance construction. Depreciation of nonutility properties is primarily computed on a straight-line basis over their estimated useful lives and over the lease term for leasehold improvements.

Depreciation expense stated as a percent of average original cost of depreciable nonutility property was, on a composite basis, 3.3% for 2003, 3.5% for 2002 and 4.2% for 2001.

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 the emission allowances in the normal course of its business to generate electricity. Accordingly, Edison International has classified emission allowances expected to be used by EME to generate power as part of nonutility property. These acquired emission allowances will be amortized over the estimated lives of the plants on a straight-line basis.

Estimated useful lives for nonutility property are as follows:

Furniture and equipment	3 years to 11 years
Building, plant and equipment	3 years to 100 years
Emission allowances	25 years to 35 years
Civil works	25 years to 100 years
Leasehold improvements	Life of lease

Purchased Power

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

In millions Year ended December 31,	2003	2002	2001
PX/ISO:			
Purchases	$ 284	$ 75	$ 775
Generation sales	—	—	324
Purchased power – PX/ISO – net	284	75	451
Purchased power – bilateral contracts	342	61	188
Purchased power – interutility/QF contracts	2,160	1,880	3,131
Total	$ 2,786	$ 2,016	$ 3,770

Net PX/ISO amounts for 2002 reflect only billing adjustments. These billing adjustments are recovered through the PROACT and have no impact on earnings. Net PX/ISO amounts for 2003 include ISO imbalance purchases and billing adjustments.

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

the CDWR. Power purchased by the CDWR for delivery to SCE's customers is not considered a cost to SCE.

Regulatory Assets and Liabilities

In accordance with accounting principles for rate-regulated enterprises, SCE records regulatory assets, which represent probable future 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.

SCE assessed the probability of recovery of its generation-related regulatory assets in light of the CPUC's March 27, 2001 decisions. These decisions and other regulatory and legislative actions did not meet SCE's prior expectation that the CPUC would provide adequate cost recovery mechanisms. SCE was unable to conclude that its generation-related regulatory assets were probable of recovery through the rate-making process as of December 31, 2000. Therefore, in accordance with accounting rules, SCE recorded a $2.5 billion after-tax charge to earnings at that time, to write off various regulatory assets.

In accordance with an October 2001 settlement agreement between the CPUC and SCE, the CPUC passed a resolution on January 23, 2002 allowing SCE to establish the PROACT regulatory asset for previously incurred energy procurement costs, retroactive to August 31, 2001. SCE fully recovered the PROACT balance during July 2003 and on August 1, 2003, transferred the PROACT overcollection to a new energy resource recovery account regulatory balancing account. The new balancing account acts as a mechanism to recover SCE's fuel costs related to its generating stations, purchased-power costs related to cogeneration and renewable contracts, existing interutility and bilateral contracts that were entered into prior to January 17, 2001, and new procurement-related costs that SCE began incurring on January 1, 2003, the date on which the CPUC transferred back to SCE the responsibility for procuring energy resources for its customers.

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

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

As part of a new accounting standard, Accounting for Asset Retirement Obligations, SCE capitalized the initial cost 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 as recorded in accordance with this standard and the recovery of the related asset retirement costs through the rate-making process. The ARO regulatory liability defers the impact on earnings of the change in accounting principle. See further discussion in "New Accounting Principles."

SCE has collected in rates amounts for the future costs of removal and decommissioning of assets, and has historically recorded these amounts in accumulated provision for depreciation. However, in accordance with recent Securities and Exchange Commission accounting guidance, the amounts accrued

in accumulated provision for depreciation for decommissioning and costs of removal were reclassified to regulatory liabilities as of December 31, 2002. Upon implementation of the new accounting standard for AROs, SCE reversed the decommissioning amounts collected for assets legally required to be removed and recorded the fair value of this ARO (included in the deferred credits and other liabilities section of the consolidated balance sheet). The cost of removal amounts collected for assets not legally required to be removed remain in regulatory liabilities as of December 31, 2003.

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

In millions December 31,	2003	2002
Current:		
PROACT – net	$ —	$ 574
Regulatory balancing accounts and other – net	(276)	(115)
	(276)	459
Long-term:		
Flow-through taxes – net	974	1,336
Rate reduction notes – transition cost deferral	949	1,215
Unamortized nuclear investment – net	601	630
Nuclear-related ARO investment – net	288	—
Unamortized coal plant investment – net	66	61
Unamortized loss on reacquired debt	222	237
Environmental remediation	71	70
ARO	(720)	—
Costs of removal	(2,020)	(4,231)
Regulatory balancing accounts and other – net	79	289
	510	(393)
Total	$ 234	$ 66

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

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

Related Party Transactions

Certain EME subsidiaries have 49% to 50% ownership in partnerships (QFs) that sell electricity generated by their project facilities to SCE under long-term power purchase agreements with terms and pricing approved by the CPUC. SCE's purchases from these partnerships were $754 million in 2003, $548 million in 2002 and $983 million in 2001.

Restricted Cash

Edison International had total restricted cash of $418 million at December 31, 2003 and $465 million at December 31, 2002. The restricted amounts included in current assets are primarily used to make

scheduled payments on the current maturities of rate reduction notes issued on behalf of SCE by a special purpose entity, as well as to serve as collateral at Edison Capital for outstanding letters of credit. In 2003, the restricted amounts were also held by others for the specific use of Edison Capital for its operations. The restricted amounts included in deferred charges in both 2003 and 2002 are primarily to pay amounts for debt payments at MEHC and EME and letter of credit expenses at EME.

Revenue

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

Since January 17, 2001, power purchased by the CDWR or through the ISO for SCE's customers is not considered a cost to SCE because SCE is acting as an agent for these transactions. Further, amounts billed to ($1.7 billion in 2003, $1.4 billion in 2002 and $2.0 billion in 2001) and collected from SCE's customers for these power purchases, CDWR bond-related costs (effective November 15, 2002) and direct access exit fees (effective January 1, 2003) are being remitted to the CDWR and are not recognized as revenue to SCE.

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

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

Stock-Based Employee Compensation

Edison International has three stock-based employee compensation plans, which are described more fully in Note 7. Edison International accounts for those plans using the intrinsic value method. Upon grant, no stock-based employee compensation cost is reflected in net income, as all options granted under those plans had an exercise price equal to the market value of the underlying common stock on the date of grant. Compensation expense recorded under the stock-compensation program was $12 million in 2003, $13 million in 2002 and $1 million in 2001. The following table illustrates the effect on net income and EPS if Edison International had used the fair-value accounting method.

In millions Year ended December 31,	2003	2002	2001
Net income, as reported	$ 821	$ 1,077	$ 1,035
Add: stock-based compensation expense using the intrinsic value accounting method – net of tax	7	8	1
Less: stock-based compensation expense using the fair-value accounting method – net of tax	9	5	5
Pro forma net income	$ 819	$ 1,080	$ 1,031
Basic EPS:			
As reported	$ 2.52	$ 3.31	$ 3.18
Pro forma	2.51	3.31	3.17
Diluted EPS:			
As reported	$ 2.50	$ 3.28	$ 3.17
Pro forma	2.49	3.29	3.16

Supplemental Accumulated Other Comprehensive Loss Information

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

In millions December 31,	2003	2002
Foreign currency translation adjustments – net	$ 146	$ (8)
Minimum pension liability – net[1]	(23)	(21)
Unrealized loss on investments – net	(7)	(9)
Unrealized losses on cash flow hedges – net	(169)	(209)
Accumulated other comprehensive loss	$ (53)	$ (247)

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

Unrealized losses on cash flow hedges included losses on interest rate hedges and commodity hedges. Unrealized losses on commodity hedges included those related to EME's hedge agreement with the State Electricity Commission of Victoria for electricity prices from the Loy Yang B project in Australia. This contract does not qualify under the normal sales and purchases exception because financial settlement of the contract occurs without physical delivery. These commodity hedge losses arise because current forecasts of future electricity prices in these markets are greater than contract prices. In addition to this contract, unrealized losses on cash flow hedges included those related to EME's share of interest rate swaps of its unconsolidated affiliates and the Loy Yang B project. Interest rate swaps entered into to hedge the floating interest rate risk on MEHC's $385 million term loan due 2006 qualify for treatment under the derivative accounting standard as cash flow hedges with appropriate adjustments made to other

comprehensive income. Included in Edison International's accumulated other comprehensive loss at December 31, 2003, was a $156 million loss related to EME's unrealized losses on cash flow hedges. Of the $156 million loss, $77 million was related to EME's commodity hedges and $79 million was related to EME's interest rate hedges.

Unrealized losses on cash flow hedges also included those related to SCE's interest rate swap. The swap terminated on January 5, 2001, but the related debt matures in 2008. The unamortized loss of $9 million (as of December 31, 2003, net of tax) on the interest rate swap will be amortized over a period ending in 2008. Approximately $2 million (after tax) of the unamortized loss on this swap will be reclassified into earnings during 2004. Additionally, SCE recorded a $1 million unrealized loss as of December 31, 2003, on an interest rate hedge that terminated on January 7, 2004.

As EME's hedged positions are realized, approximately $13 million (after tax) of the net unrealized gains on cash flow hedges at December 31, 2003 are expected to be reclassified into earnings during 2004. EME expects that when the hedged items are recognized in earnings, the net unrealized gains associated with them will be offset. The maximum period over which EME has designated a cash flow hedge, excluding those forecasted transactions related to the payment of variable interest on existing financial instruments, is 13 years. Actual amounts ultimately reclassified into earnings over the next 12 months could vary materially from this estimated amount as a result of changes in market conditions.

Supplemental Cash Flows Information

Edison International supplemental cash flows information is:

In millions Year ended December 31,	2003	2002	2001
Cash payments for interest and taxes:			
Interest – net of amounts capitalized	$ 1,280	$ 1,113	$ 1,192
Tax payments (receipts)	230	(301)	(70)
Non-cash investing and financing activities:			
Obligation to fund investments in partnerships and unconsolidated subsidiaries	—	—	$ 4
Obligation to fund investment in acquisition	$ 8	—	—
Details of long-term debt exchange offer:			
Variable rate notes redeemed	$ (966)	—	—
First and refunding mortgage bonds issued	966	—	—
Details of debt exchange:			
Retirement of senior secured credit facility	$ (700)	—	—
Cash paid	500	—	—
Short-term credit line utilized	200	—	—
Details of assets acquired:			
Fair value of assets acquired	$ 336	$ 16	$ 898
Cash paid for acquisitions	(278)	(16)	(97)
Liabilities assumed	$ 58	$ —	$ 801
Details of senior secured credit facility transaction:			
Retirement of credit facility	—	$ 1,650	—
Cash paid on retirement of credit facility	—	(50)	—
Senior secured credit facility replacement	—	$ 1,600	—

Translation of Foreign Financial Statements

Assets and liabilities of most foreign operations are translated at end of period rates of exchange and the income statements are translated at the average rates of exchange for the year. Gains or losses from translation of foreign currency financial statements are included in accumulated other comprehensive income in shareholders' equity. Gains or losses resulting from foreign currency transactions are included in other nonoperating income or deductions. Foreign currency transaction gains/(losses) were $2 million, $(8) million and $2 million for 2003, 2002 and 2001, respectively.

Note 2. Regulatory Matters

CDWR Power Purchases and Revenue Requirement Proceedings

In accordance with an emergency order by the Governor of California, the CDWR began making emergency power purchases for SCE's customers on January 17, 2001. In February 2001, a California law was enacted which authorized the CDWR to: (1) enter into contracts to purchase electric power and sell power at cost directly to SCE's retail customers; and (2) issue bonds to finance those electricity

purchases. During the fourth quarter of 2002, the CDWR issued $11 billion in bonds to finance its electricity purchases. The CDWR's total statewide power charge and bond charge revenue requirements are allocated by the CPUC among the customers of SCE, Pacific Gas and Electric (PG&E) and San Diego Gas & Electric (SDG&E). Amounts billed to and collected from SCE's customers for electric power purchased and sold by the CDWR (approximately $1.7 billion in 2003) are remitted directly to the CDWR and are not recognized as revenue by SCE.

CPUC Litigation Settlement Agreement

During the California energy crisis, prices charged by sellers of wholesale power escalated far beyond what SCE was permitted by the CPUC to charge its customers. In November 2000, SCE filed a lawsuit against the CPUC in federal district court seeking a ruling that SCE is entitled to full recovery of its electricity procurement costs incurred during the energy crisis in accordance with the tariffs filed with the FERC. In October 2001, SCE and the CPUC entered into a settlement of SCE's lawsuit against the CPUC. A key element of the 2001 CPUC settlement agreement was the establishment of a $3.6 billion regulatory balancing account, called the PROACT, as of August 31, 2001. The Utility Reform Network (TURN) and other parties appealed to the United States Court of Appeals for the Ninth Circuit (Ninth Circuit) seeking to overturn the stipulated judgment of the federal district court that approved the 2001 CPUC settlement agreement. On September 23, 2002, the Ninth Circuit issued its opinion affirming the federal district court on all claims, with the exception of the challenges founded upon California state law, which the Ninth Circuit referred to the California Supreme Court.

On August 21, 2003, the California Supreme Court issued its decision on the certified questions on challenges founded upon California state law, concluding that the 2001 CPUC settlement agreement did not violate California law in any of the respects raised by the Ninth Circuit. Specifically, the California Supreme Court concluded that: (1) the commissioners of the CPUC had the authority to propose the stipulated judgment under the provisions of California's restructuring statute, Assembly Bill 1890, as amended or impacted by subsequent legislation; (2) the procedures employed by the CPUC in entering the stipulated judgment did not violate California's open meeting law for public agencies; and (3) the stipulated judgment did not violate California's public utilities code by allegedly altering rates without a public hearing and issuance of findings.

On October 22, 2003, the California Supreme Court denied TURN's petition for rehearing of the decision. The matter was returned to the Ninth Circuit for final disposition, subject to any efforts by TURN to pursue further federal appeals. On December 19, 2003, the Ninth Circuit unanimously affirmed the original stipulated judgment of the federal district court, and no petition for rehearing was filed. On January 12, 2004, the Ninth Circuit issued its mandate, relinquishing jurisdiction of the case and returning jurisdiction to the federal district court. TURN and those parties whose appeals to the Ninth Circuit were consolidated with TURN's appeal currently have 90 days from December 19, 2003 in which to seek discretionary review from the United States Supreme Court. SCE continues to believe it is probable that recovery of its past procurement costs through regulatory mechanisms, including the PROACT, will not be invalidated. However, SCE cannot predict with certainty the ultimate outcome of further legal proceedings, if any.

Electric Line Maintenance Practices Proceeding

In August 2001, the CPUC issued an order instituting investigation regarding SCE's overhead and underground electric line maintenance practices. The order was based on a report issued by the CPUC's Consumer Protection and Safety Division, which alleged a pattern of noncompliance with the CPUC's general orders for the maintenance of electric lines for 1998–2000. The order also alleged that noncompliant conditions were involved in 37 accidents resulting in death, serious injury or property damage. The Consumer Protection and Safety Division identified 4,817 alleged violations of the general

orders during the three-year period; and the order put SCE on notice that it could be subject to a penalty of between $500 and $20,000 for each violation or accident. In its opening brief on October 21, 2002, the Consumer Protection and Safety Division recommended that SCE be assessed a penalty of $97 million.

On June 19, 2003, a CPUC administrative law judge issued a presiding officer's decision on the Consumer Protection and Safety Division report. The decision did the following:

- Fined SCE $576,000 for 2% of the alleged violations involving death, injury or property damage, failure to identify unsafe conditions or exceeding required inspection intervals. The decision did not find that any of the alleged violations compromised the integrity or safety of SCE's electric system or were excessive compared to other utilities.

- Ordered SCE to consult with the Consumer Protection and Safety Division and refine SCE's maintenance priority system consistent with the decision.

- Adopted an interpretation that all of SCE's nonconformances with the CPUC's general orders for the maintenance of electric lines are violations subject to potential penalty.

On July 21, 2003, SCE filed an appeal with the CPUC challenging, among other things, the decision's interpretation of nonconformance. The Consumer Protection and Safety Division also appealed, challenging the fact that the decision did not penalize SCE for 4,721 of the 4,817 alleged violations. A final decision is scheduled to be issued on March 16, 2004.

Generation Procurement Proceedings

SCE resumed power procurement responsibilities for its residual-net short position on January 1, 2003, pursuant to CPUC orders and California statutes passed in 2002. The current regulatory and statutory framework requires SCE to assume limited responsibilities for CDWR contracts allocated by the CPUC, and provide full power procurement responsibilities on the basis of annual short-term procurement plans, long-term resource plans and increased procurement of renewable resources.

Short-Term Procurement Plan

In 2003, SCE operated under a CPUC-approved short-term procurement plan, which includes contracts entered into during a transitional period beginning in August 2002 for deliveries in 2003 and the allocation of CDWR contracts. In December 2003, the CPUC adopted a 2004 procurement plan for SCE, which established a target level for spot market purchases equal to 5% of monthly need, and allowed SCE to enter into contracts of up to five years.

Long-Term Resource Plan

On April 15, 2003, SCE filed its long-term resource plan with the CPUC, which includes a 20-year forecast. SCE's long-term resource plan included both a preferred plan and an interim plan (both described below). On January 22, 2004, the CPUC issued a decision which did not adopt any long-term resource plan, but adopted a framework for resource planning. Until the CPUC approves a long-term resource plan for SCE, SCE will operate under its interim resource plan.

- Preferred Resource Plan: The preferred resource plan contains long-term commitments intended to encourage investment in new generation and transmission infrastructure, increase long-term reliability and decrease price volatility. These commitments include energy efficiency and demand-response investments, additional renewable resource contracts that will meet or exceed the requirements of

legislation passed in 2002, additional utility and third-party owned generation, and new major transmission projects.

- Interim Resource Plan: The interim resource plan, by contrast, relies exclusively on new short- and medium-term contracts with no long-term resource commitments (except for new renewable contracts).

In its long-term resource plan filing, SCE maintained that implementation of its preferred resource plan requires resolution of various issues including: (1) stabilizing SCE's customer base; (2) restoring SCE's investment-grade creditworthiness; (3) restructuring regulations regarding energy efficiency and demand-response programs; (4) removing barriers to transmission development; (5) modifying prior decisions, which impede long-term procurement; and (6) adopting a commercially realistic cost-recovery framework that will enable utilities to obtain financing and enable contracting for new generation.

Under the framework adopted in the CPUC's January 22, 2004 decision, all load-serving entities in California have an obligation to procure sufficient resources to meet their customers' needs. This resource adequacy requirement phases in over the 2005–2008 period and requires planning reserve margins of 15% to 17% of peak load. The decision requires SCE to enter into forward contracts for 90% of SCE's summer peaking needs a year in advance and to file a revised long-term resource plan in 2004. The decision does not comprehensively address important issues SCE has raised about its customer base, recovery of indirect procurement costs (including debt equivalence) and other matters.

Procurement of Renewable Resources

As part of SCE's resumption of power procurement, in accordance with a California statute passed in 2002, SCE is required to increase its procurement of renewable resources by at least 1% of its annual electricity sales per year so that 20% of its annual electricity sales are procured from renewable resources by no later than December 31, 2017. In June 2003, the CPUC issued a decision adopting preliminary rules and guidance on renewable procurement-related issues, including penalties for noncompliance with renewable procurement targets. As of December 31, 2003, SCE procured approximately 18% of its annual electricity from renewable resources.

SCE has received bids for renewable resource contracts in response to a solicitation it made in August 2003, and is proceeding to enter into negotiations for contracts with some bidders based upon its preliminary bid evaluation.

CDWR Contract Allocation and Operating Order

The CDWR power-purchase contracts entered into as a result of the California energy crisis have been allocated on a contract-by-contract basis among SCE, PG&E and SDG&E, in accordance with a 2002 CPUC decision. SCE only assumes scheduling and dispatch responsibilities and acts only as a limited agent for the CDWR for contract implementation. Legal title, financial reporting and responsibility for the payment of contract-related bills remain with the CDWR. The allocation of CDWR contracts to SCE significantly reduces SCE's residual-net short and also increases the likelihood that SCE will have excess power during certain periods. SCE has incorporated the CDWR contracts allocated to it in its procurement plans. Wholesale revenue from the sale of excess power, if any, is prorated between the CDWR and SCE.

SCE's maximum annual disallowance risk exposure for contract administration, including administration of allocated CDWR contracts and least cost dispatch of CDWR contract resources, is $37 million. In addition, gas procurement, including hedging transactions, associated with the CDWR contracts is included within the cap.

Holding Company Proceeding

In April 2001, the CPUC issued an order instituting investigation that reopened the past CPUC decisions authorizing utilities to form holding companies and initiated an investigation into, among other things: (1) whether the holding companies violated CPUC requirements to give first priority to the capital needs of their respective utility subsidiaries; (2) any additional suspected violations of laws or CPUC rules and decisions; and (3) whether additional rules, conditions, or other changes to the holding company decisions are necessary.

In January 2002, the CPUC issued an interim decision interpreting the CPUC requirement that the holding companies give first priority to the capital needs of their respective utility subsidiaries. The decision stated that, at least under certain circumstances, holding companies are required to infuse all types of capital into their respective utility subsidiaries when necessary to fulfill the utility's obligation to serve its customers. The decision did not determine whether any of the utility holding companies had violated this requirement, reserving such a determination for a later phase of the proceedings. In February 2002, SCE and Edison International filed an application before the CPUC for rehearing of the decision. In July 2002, the CPUC affirmed its earlier decision on the first priority requirement and also denied Edison International's request for a rehearing of the CPUC's determination that it had jurisdiction over Edison International in this proceeding. In August 2002, Edison International and SCE jointly filed a petition in California state court requesting a review of the CPUC's decisions with regard to first priority requirements, and Edison International filed a petition for a review of the CPUC decision asserting jurisdiction over holding companies. PG&E and SDG&E and their respective holding companies filed similar challenges, and all cases have been transferred to the First District Court of Appeals in San Francisco. On November 26, 2003, the Court of Appeals issued an order indicating it would hear the cases but not decide the merits of the petitions. Oral argument was held before the Court of Appeals on March 5, 2004, and the Court of Appeals is expected to rule within 90 days.

Mohave Generating Station and Related Proceedings

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

Due to the lack of progress in negotiations with the Tribes and other parties to resolve several coal and water supply issues, SCE's application stated that SCE would probably be unable to extend Mohave's operation beyond 2005. The uncertainty over a 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 pollution-control equipment that must be put in place in order for Mohave to continue to operate beyond 2005, pursuant to a 1999 consent decree concerning air quality.

Negotiations are continuing among the relevant parties in an effort to resolve the coal and water supply issues, but no resolution has been reached. The Mohave co-owners, the Tribes and the federal government have recently finalized a memorandum of understanding under which the Mohave co-owners will fund, subject to the terms and conditions of the memorandum of understanding, a $6 million study of a possible alternative groundwater source for the slurry water. The study is expected to begin in early 2004. SCE and other parties submitted further testimony and made various other filings in 2003 in SCE's application proceeding. On February 9, 2004, the CPUC held a prehearing conference to discuss whether

additional testimony and hearings are needed to determine the future of the plant. The CPUC has not issued any ruling as result of the prehearing conference, but has indicated that further testimony can be expected in early to mid-2004. The outcome of the coal and water negotiations and SCE's application are not expected to impact Mohave's operation through 2005, but could have a major impact on SCE's long-term resource plan.

For additional matters related to Mohave, see "Navajo Nation Litigation" in Note 10.

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

Wholesale Electricity and Natural Gas Markets

In 2000, the FERC initiated an investigation into the justness and reasonableness of rates charged by sellers of electricity in the PX/ISO markets. On March 26, 2003, the FERC staff issued a report concluding that there had been pervasive gaming and market manipulation of both the electric and natural gas markets in California and on the West Coast during 2000–2001 and describing many of the techniques and effects of that market manipulation. 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. Under the 2001 CPUC settlement agreement, mentioned in "CPUC Litigation Settlement Agreement," 90% of any refunds actually realized by SCE will be refunded to customers, except for the El Paso Natural Gas Company settlement agreement discussed below.

El Paso Natural Gas Company entered into a settlement agreement with parties to a class action lawsuit (including SCE, PG&E and the State of California) settling claims stated in proceedings at the FERC and in San Diego County Superior Court that El Paso Natural Gas Company had manipulated interstate capacity and engaged in other anticompetitive behavior in the natural gas markets in order to unlawfully raise gas prices at the California border in 2000–2001. The San Diego County Superior Court approved the settlement on December 5, 2003. Notice of appeal of that judgment was filed by a party to the action on February 6, 2004. Accordingly, until the appeal is resolved, the judgment is not final and no refunds will be paid. Pursuant to a CPUC decision, SCE will refund to customers any amounts received under the terms of the El Paso Natural Gas Company settlement (net of legal and consulting costs) through its energy resource recovery account mechanism. In addition, amounts El Paso Natural Gas Company refunds to the CDWR will result in equivalent reductions in the CDWR's revenue requirement allocated to SCE.

On February 24, 2004, SCE and PG&E entered into a settlement agreement with The Williams Cos. and Williams Power Company, providing for approximately $140 million in refunds against some of Williams' power charges in 2000–2001. The allocation of refunds under the settlement agreement has not been determined. The settlement is subject to the approval of the FERC, the CPUC and the PG&E bankruptcy court.

Note 3. Derivative Instruments and Hedging Activities

Edison International's risk management policy allows the use of derivative financial instruments to manage financial exposure on its investments and fluctuations in interest rates, foreign currency exchange

rates, emission and transmission rights, and oil, gas and energy prices but prohibits the use of these instruments for speculative or trading purposes, except at EME's trading operations unit.

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

SCE recorded its interest rate swap agreement (terminated January 5, 2001) and its block forward power-purchase contracts at fair value effective January 1, 2001. The unamortized loss of $9 million (as of December 31, 2003, net of tax) on the interest rate swap will be amortized over a period ending in 2008, when the related debt matures.

In December 2003, SCE entered into an interest rate lock to hedge its exposure to changes in interest rates for $825 million of anticipated issuances of first mortgage bonds. SCE recorded a $1 million liability as of December 31, 2003, representing the fair value of the interest rate lock. The lock expired on January 7, 2004, the pricing date of $975 million of new mortgage bonds, resulting in a payment of $6 million to the counterparties due to a decline in treasury rates. This loss will be treated as a debt discount and amortized over the life of the mortgage bonds.

SCE has bilateral forward power contracts, which are considered normal purchases under accounting rules. SCE is exposed to credit loss in the event of nonperformance by the counterparties to its bilateral forward contracts, but does not expect the counterparties to fail to meet their obligations. The counterparties are required to post collateral depending on the creditworthiness of each counterparty.

In October and November 2001, SCE purchased $209 million of call options that mitigated its exposure to increases in natural gas prices during 2002 and 2003. This amount was recovered through a balancing account mechanism. Amounts paid to QFs for energy are based on natural gas prices. Any fair value changes for gas call options are offset through a regulatory balancing account; therefore, fair value changes do not affect earnings. In fourth quarter 2003, SCE purchased $4 million of call options to hedge some gas price exposure for 2004.

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

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

In 2001, EME recorded a $250,000 (after tax) increase to income from continuing operations, a $6 million (after tax) increase to income from discontinued operations and a $230 million (after tax)

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

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

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

In June 2003, clarifying guidance was issued related to derivative instruments and hedging activities. The guidance is related to pricing adjustments in contracts that qualify under the normal purchases and normal sales exception under derivative instrument accounting. This implementation guidance became effective

on October 1, 2003, but did not have any impact on Edison International's consolidated financial statements.

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

Under EME's fixed to variable swap agreements, the fixed interest rate payments are at a weighted average rate of 6.39% and 6.91% at December 31, 2003 and 2002, respectively. Variable rate payments under EME's corporate agreements were based on six-month LIBOR capped at 9% at December 31, 2001. Variable rate payments pertaining to its foreign subsidiary agreements are based on an equivalent interest rate benchmark to LIBOR. The weighted average rate applicable to these agreements was 5.36% and 6.18% at December 31, 2003 and 2002, respectively. Under the variable to fixed swap agreements, EME will pay counterparties interest at a weighted average fixed rate of 6.74% and 6.96% at December 31, 2003 and 2002, respectively. Counterparties will pay EME interest at a weighted average variable rate of 5.07% and 5.10% at December 31, 2003 and 2002, respectively. The weighted average variable interest rates are based on LIBOR or equivalent interest rate benchmarks for foreign denominated interest rate swap agreements. Under EME's interest rate options, the weighted average strike interest rate is was 6.24% and 6.90% and December 31, 2003 and 2002, respectively.

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

MEHC, a wholly owned indirect subsidiary of Edison International, has two interest rate swaps to hedge floating interest rate risk on its term loan. These contracts qualify for treatment as cash flow hedges with appropriate adjustments made to other comprehensive income. During the years ended December 31, 2003 and 2002, MEHC recorded decreases to other comprehensive income of $3 million (after tax) and $5 million (after tax), respectively, resulting from unrealized holding losses on these contracts. Under the variable-to-fixed swap agreements, MEHC will pay counterparties interest at a weighted average fixed rate of 2.84% and 3.04% at December 31, 2003 and 2002, respectively; counterparties will pay interest at a weighted average variable rate based on LIBOR of 1.15% and 1.63% at December 31, 2003 and 2002, respectively.

Edison Capital had an interest rate swap and an interest rate cap in place during 2003. The purpose of the interest rate swap was to convert floating rate debt to fixed rate debt to hedge changes in interest rates. The purpose of the interest rate cap was to limit Edison Capital's exposure to an increase in interest rates. In 2003, Edison Capital made payments on its swap agreement at a weighted average rate of 6.79% and received payments at a weighted average rate of 1.17%. In 2003, Edison Capital received no payments on its cap agreement.

Fair values of financial instruments are:

In millions December 31,	2003	2002
Derivatives:		
Interest rate hedges	$ (35)	$ (56)
Interest rate options	(1)	(2)
Commodity price		
Electricity	(126)	(100)
Natural gas	3	77
Foreign currency forward exchange agreements	(2)	—
Cross currency interest rate swaps	(91)	(2)
Other:		
Decommissioning trusts	2,530	2,210
Long-term receivables	6	6
DOE decommissioning and decontamination fees	(18)	(22)
QF power contracts	(32)	(70)
Long-term debt	(11,833)	(9,952)
Long-term debt due within one year	(2,029)	(2,812)
Preferred stock to be redeemed within one year	(9)	(8)
Company-obligated mandatorily redeemable securities of subsidiaries	—	(741)
Other preferred securities subject to mandatory redemption	(303)	(375)
Trading Activities:		
Assets	104	109
Liabilities	(12)	(17)

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

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

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

Other fair values are based on: quoted market prices for decommissioning trusts and long-term receivables; discounted future cash flows for United States Department of Energy (DOE) decommissioning and decontamination fees; and brokers' quotes for long-term debt, company-obligated mandatorily redeemable securities of subsidiaries, and preferred stock and preferred securities subject to mandatory redemption.

Quoted market prices are used to determine the fair values of trading instruments. Assets from trading and price risk management activities include the fair value of open financial positions related to trading activities and the present value of net amounts receivable from structured transactions. Liabilities from trading and price risk management activities include the fair value of open financial positions related to trading activities and the present value of net amounts payable from structured transactions.

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

Note 4. Liabilities and Lines of Credit

Long-Term Debt

In fourth quarter 2003, Edison International adopted a new accounting interpretation regarding VIEs which required Edison International to deconsolidate three special purpose entities, EIX Trusts I and II, and Mission Capital, L.P. As a result of these deconsolidations, the bonds and securities associated with these financing entities are now included in long-term debt on Edison International's consolidated balance sheet. Under prior accounting treatment, these bonds and securities would have been eliminated in consolidation and the bonds and securities held by the special purpose entities would have been included in company-obligated mandatorily redeemable securities of subsidiary on the consolidated balance sheet.

Almost all SCE properties are subject to a trust indenture lien. SCE has pledged first and refunding mortgage bonds as security for borrowed funds obtained from pollution-control bonds issued by government agencies. SCE used these proceeds to finance construction of pollution-control facilities. Bondholders have limited discretion in redeeming certain pollution-control bonds, and SCE has arrangements with securities dealers to remarket or purchase them if necessary. In December 2000 and early 2001, as a result of investors' concerns regarding SCE's liquidity difficulties and overall financial condition, SCE had to repurchase $550 million of pollution-control bonds that could not be remarketed in accordance with their terms. On March 1, 2002, SCE remarketed $196 million of the pollution-control bonds that SCE had repurchased in late 2000.

Debt premium, discount and issuance expenses are amortized over the life of each issue. Under CPUC rate-making procedures, debt reacquisition expenses are amortized over the remaining life of the reacquired debt or, if refinanced, the life of the new debt. California law prohibits SCE from incurring or guaranteeing debt for its nonutility affiliates.

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

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

MEHC's consolidated debt at December 31, 2003 was $7.4 billion, including $693 million of debt maturing in December 2004 that is owed by EME's largest subsidiary, Edison Mission Midwest Holdings. Edison Mission Midwest Holdings is not expected to have sufficient cash to repay the

$693 million debt due in December 2004. Edison Mission Midwest Holdings plans to refinance the $693 million debt obligation prior to its expiration in December 2004. EME believes that Edison Mission Midwest Holdings will be able to refinance the debt maturing in December 2004 through a combination of borrowings in the bank and capital markets. Completion of this refinancing is subject to a number of uncertainties, including availability of new credit from the capital and bank markets. Accordingly, there is no assurance that Edison Mission Midwest Holdings will be able to extend or refinance this debt when it becomes due or that the terms will not be substantially different from those under the current credit facility.

On December 11, 2003, EME's subsidiary, Mission Energy Holdings International, Inc., received funding under a three-year, $800 million secured loan. Interest on this secured loan is based on LIBOR (with a LIBOR floor of 2%) plus 5%. After payment of transaction expenses, a portion of the net proceeds from this financing was used to make an equity contribution of $550 million to Edison Mission Midwest Holdings that, together with cash on hand, was used to repay Edison Mission Midwest Holdings' $781 million indebtedness due December 11, 2003. The remaining net proceeds from this financing were used to make a deposit of cash collateral of approximately $67 million under a new letter of credit facility and to repay approximately $160 million of indebtedness of a foreign subsidiary under the Coal and Capex facility guaranteed by EME. Mission Energy Holdings International owns substantially all of EME's international operations through its subsidiary, MEC International B.V.

To isolate EME from credit downgrades of Edison International and SCE and to help preserve the value of EME, EME has adopted certain provisions (ring-fencing) in the form of amendments to its articles of incorporation and bylaws. The provisions include the appointment of an independent EME director whose consent is required for EME to: consolidate or merge with any entity that does not have substantially similar provisions in its organizational documents; institute or consent to bankruptcy, insolvency or similar proceedings; or declare or pay dividends unless certain conditions exist. Such conditions are that EME has an investment grade rating and receives rating agency confirmation that the dividend will not result in a downgrade, or such dividends do not exceed $32.5 million in any quarter and EME meets an interest coverage ratio of 2.2 to 1 for the immediately preceding four quarters.

Long-term debt is:

In millions December 31,	2003	2002
First and refunding mortgage bonds:		
2004 – 2026 (5.875% to 8.00% and variable)	$ 1,816	$ 2,275
Rate reduction notes:		
2004 – 2007 (6.38% to 6.42%)	985	1,232
Pollution-control bonds:		
2005 – 2040 (5.125% to 7.2% and variable)	1,216	1,216
Bonds repurchased	(354)	(354)
Debentures and notes:		
2004 – 2039 (2.31% to 13.5% and variable)	9,927	9,922
Subordinated debentures:		
2024 – 2044 (8.375% to 9.875%)	254	100
Long-term debt due within one year	(2,003)	(2,761)
Unamortized debt discount – net	(54)	(52)
Total	$ 11,787	$ 11,578

Note: Rates and terms as of December 31, 2003.

Long-term debt maturities and sinking-fund requirements for the next five years are: 2004 – $2.0 billion; 2005 – $753 million; 2006 – $1.8 billion; 2007 – $1.7 billion; and 2008 – $1.3 billion.

Long-term debt due within one year includes $29 million and $31 million of debt related to Edison Capital's Storm Lake project that is not due until 2011 and 2017, respectively. This debt has been reclassified to long-term debt due within one year as a result of various defaults asserted by the lenders and related to the Enron bankruptcy among other things, which may give the lenders the ability to call the loans due and payable. However, the lenders are currently discussing resolution of the defaults with Storm Lake and are not actively pursuing remedies.

In January 2004, SCE issued $975 million of first and refunding mortgage bonds. The issuance included $300 million of 5% bonds due in 2014, $525 million of 6% bonds due in 2034 and $150 million of floating rate bonds due in 2006. The proceeds were used to redeem $300 million of 7.25% first and refunding mortgage bonds due March 2026, $225 million of 7.125% first and refunding mortgage bonds due July 2025, $200 million of 6.9% first and refunding mortgage bonds due October 2018, and $100 million of junior subordinated deferrable interest debentures due June 2044. In March 2004, SCE remarketed approximately $550 million of pollution-control bonds with varying maturity dates ranging from 2008 to 2040.

During January and February 2004, Edison International repurchased approximately $46 million of its outstanding $618 million of 6-7/8% notes, leaving a remaining balance of $572 million of notes due September 2004.

Short-Term Debt

Short-term debt is used to finance fuel inventories, balancing account undercollections and general cash requirements, including power purchase payments.

Short-term debt is:

In millions December 31,	2003	2002
Bank loans	$ 200	$ —
Floating rate notes	—	78
Other short-term debt	52	—
Total	$ 252	$ 78
Weighted-average interest rate	3.2%	6.1%

Lines of Credit

At December 31, 2003, Edison International's subsidiaries had lines of credit totaling $845 million, with various expiration dates, and when available, can be drawn down at negotiated or bank index rates. EME had total lines of credit of $145 million, with all of it available to finance general cash requirements. SCE had drawn $200 million on a $700 million line of credit.

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

Preferred Securities Subject to Mandatory Redemption

In compliance with a new accounting standard, effective July 1, 2003, Edison International reclassified its company-obligated mandatorily redeemable securities, its other mandatorily redeemable preferred securities and SCE's preferred stock subject to mandatory redemption to the liabilities section of its consolidated balance sheet. These items were previously classified between liabilities and equity.

Company-Obligated Mandatorily Redeemable Securities of Subsidiary

In 1999, Edison International (the parent company) issued, through affiliates (EIX Trusts I and II), $500 million of 7.875% cumulative quarterly income preferred securities and $325 million of 8.6% cumulative quarterly income preferred securities, at a price of $25 per security. The 7.875% securities have a stated maturity of July 2029, but are redeemable at the option of Edison International, in whole or in part, beginning July 2004. The 8.6% securities have a stated maturity of October 2029, but are redeemable at the option of Edison International, in whole or in part, beginning October 2004. Both of these securities are guaranteed by Edison International. In order to reduce its cash requirements, in May 2001, the parent company deferred the interest payments in accordance with the terms of its outstanding quarterly income debt securities issued to an affiliate. This caused a corresponding deferral of distributions on quarterly income preferred securities issued by the affiliate. Interest payments may be deferred for up to 20 consecutive quarters. During the deferral period, the principal of the debt securities and each unpaid interest installment continues to accrue interest at the applicable coupon rate. All interest in arrears must be paid in full at the end of the deferral period. The parent company cannot pay dividends on or purchase its common stock while interest is being deferred. In December 2003, Edison International made aggregate payments of approximately $205 million, which covered repayment of the deferred distributions, with interest, and payment of the distribution due on November 30, 2003.

In November 1994, EME issued, through a limited partnership (Mission Capital, L.P.), 3.5 million shares of 9.875% cumulative monthly income preferred securities, at a price of $25 per security and invested the proceeds in 9.875% junior subordinated deferrable interest debentures due 2024. These securities are redeemable at the option of the partnership (EME is the sole general partner), in whole or in part, with mandatory redemption in 2024 at a redemption price of $25 per security plus accrued and unpaid distributions. In August 1995, EME also issued, through a limited partnership, 2.5 million shares of 8.5% cumulative monthly income preferred securities, at a price of $25 per security and invested the proceeds in 8.5% junior subordinated deferrable interest debentures due 2025. These securities are redeemable at the option of the partnership, in whole or in part, with mandatory redemption in 2025 at a redemption price of $25 per security plus accrued and unpaid distributions. EME issued a guarantee in favor of its preferred securities holders, which ensures the payments of distributions declared on the preferred securities, payments upon liquidation of the limited partnership and payments on redemption for securities called for redemption by the limited partnership. No securities have been redeemed as of December 31, 2003.

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

- declare or pay any dividend on, or purchase, acquire or make a distribution or liquidation payment with respect to, any of its common or preferred stock;

- acquire for cash or other property any indebtedness of any affiliate of EME (other than affiliates of EME which meet specified requirements) for money borrowed; or

- make any loan or advance to, or guarantee or become contingently liable in respect of indebtedness of, any affiliate of EME (other than affiliates of EME which meet specified requirements).

Further, as long as any preferred securities remain outstanding, EME will not be able to declare or pay dividends on, or purchase, any of its common stock if at such time it is in default on its payment obligations under the guarantee or the subordinated indenture unless EME has given notice of the extended interest payment period described above.

In fourth quarter 2003, Edison International adopted a new accounting interpretation regarding VIEs which required Edison International to deconsolidate three special purpose entities, EIX Trusts I and II, and Mission Capital, L.P. As a result of these deconsolidations, the bonds and securities associated with these entities are now included in long-term debt on Edison International's consolidated balance sheet. Under the prior accounting treatment, these securities would have been eliminated in consolidation and reflected as company-obligated mandatorily redeemable securities of subsidiary.

Other Preferred Securities Subject to Mandatory Redemption

SCE has 12 million authorized shares of preferred stock subject to mandatory redemption. All cumulative preferred stock is redeemable. Mandatorily redeemable preferred stock is subject to sinking-fund provisions. When preferred shares are redeemed, the premiums paid, if any, are charged to expense.

SCE's preferred stock redemption requirements for the next five years are: 2004 – $9 million; 2005 – $9 million; 2006 – $9 million; 2007 – $69 million; and 2008 – $54 million.

SCE's cumulative preferred stock subject to mandatory redemption is:

Dollars in millions, except per-share amounts	December 31,		2003	2002
	December 31, 2003			
	Shares Outstanding	Redemption Price		
$100 par value:				
6.05% Series	693,800	$ 100.00	$ 69	$ 75
7.23	807,000	100.00	81	81
Preferred stock to be redeemed within one year			(9)	(9)
Total			$ 141	$ 147

In 2001, SCE did not redeem any preferred stock. In 2002, SCE redeemed 1,000,000 shares of 6.45% Series preferred stock. In 2003, SCE redeemed 56,200 shares of 6.05% Series preferred stock. SCE did not issue any preferred stock in the last three years.

The 7.23% Series preferred stock has mandatory sinking funds, requiring SCE to redeem at least 50,000 shares per year from 2002 through 2006, and 750,000 shares in 2007. However, SCE is allowed to credit previously repurchased shares against the mandatory sinking fund provisions. Since SCE had previously repurchased 193,000 shares of this series, no shares were redeemed in 2002 or 2003. At December 31, 2003, SCE had 93,000 of previously repurchased, but not retired, shares available to credit against the mandatory sinking fund provisions.

During 2001, a subsidiary of EME issued $104 million of redeemable preferred shares (250 million shares at a price of one New Zealand dollar per share with a dividend rate of 6.03%). The shares are redeemable in July 2006 at the issuance price. At December 31, 2003, total accumulated dividends were approximately $5 million. Optional early redemption may occur if the holders pass an extraordinary resolution to redeem the shares if certain EME subsidiaries cease to be subsidiaries of EME or in the case of certain defaults of the security trust deed. The security trust deed secures a limited recourse guarantee by an EME subsidiary's payment obligations to holders of the redeemable preferred shares.

Note 5. Preferred Securities Not Subject to Mandatory Redemption

SCE's authorized shares are: $25 cumulative preferred – 24 million and preference – 50 million. All cumulative preferred stock is redeemable. When preferred shares are redeemed, the premiums paid, if any, are charged to common equity.

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

Dollars in millions, except per-share amounts	December 31,		2003	2002
	December 31, 2003			
	Shares Outstanding	Redemption Price		
$25 par value:				
4.08% Series	1,000,000	$25.50	$ 25	$ 25
4.24	1,200,000	25.80	30	30
4.32	1,653,429	28.75	41	41
4.78	1,296,769	25.80	33	33
Total			$129	$129

Note 6. Income Taxes

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

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

Edison International's subsidiary, EME, does not provide for federal income taxes or tax benefits on the undistributed earnings or losses of its international subsidiaries because such earnings are reinvested indefinitely or would not be subject to additional income taxes if repatriated. EME reviewed undistributed earnings of its international subsidiaries and concluded that no additional income taxes are required to be provided since (1) its international holding company had negative retained earnings and negative accumulated earnings and profits for federal income tax purposes, (2) distributions from lower tier international subsidiaries would either not be taxable or could be distributed without additional income taxes and (3) its international holding company had outstanding indebtedness to domestic subsidiaries of $445 million at December 31, 2003, which could be repaid without incurring additional income taxes.

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

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

In millions Year ended December 31,	2003	2002	2001
Domestic	$ 787	$ 1,379	$ 3,962
Foreign	205	147	87
Total continuing operations	992	1,526	4,049
Discontinued operations	84	(74)	(2,223)
Change in accounting	(13)	—	—
Total	$ 1,063	$ 1,452	$ 1,826

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

In millions Year ended December 31,	2003	2002	2001
Current:			
Federal	$ 194	$ 585	$ (215)
State	100	111	—
Foreign	54	38	30
	348	734	(185)
Deferred:			
Federal	(101)	(312)	1,422
State	(67)	(43)	406
Foreign	33	12	4
	(135)	(343)	1,832
Total continuing operations	213	391	1,647
Discontinued operations	33	(16)	(856)
Change in accounting	(4)	—	—
Total	$ 242	$ 375	$ 791

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

In millions December 31,	2003	2002
Deferred tax assets:		
Property-related	$ 243	$ 178
Unrealized gains or losses	365	274
Investment tax credits	68	73
Regulatory balancing accounts	144	5,365
Deferred income	177	172
Decommissioning	166	—
Accrued charges	344	501
Loss carryforwards	373	448
Other	211	240
Subtotal	2,091	7,251
Valuation allowance	(74)	(21)
Total	$ 2,017	$ 7,230
Deferred tax liabilities:		
Property-related	$ 4,337	$ 4,424
Leveraged leases	2,055	2,044
Capitalized software costs	160	204
Regulatory balancing accounts	360	5,606
Unrealized gains and losses	262	171
Other	302	353
Total	$ 7,476	$12,802
Accumulated deferred income taxes – net	$ 5,459	$ 5,572
Classification of accumulated deferred income taxes:		
Included in deferred credits	$ 5,967	$ 6,099
Included in current assets	$ 508	$ 527

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

Year ended December 31,	2003	2002	2001
Federal statutory rate	35.0%	35.0%	35.0%
Resolution of FERC rate case	(7.6)	—	—
Housing credits	(2.7)	(2.4)	(1.2)
Property-related and other	(3.9)	(8.3)	0.6
Favorable resolution of audit	(3.6)	(2.4)	—
State tax – net of federal deduction	4.3	3.7	6.3
Effective tax rate	21.5%	25.6%	40.7%

Edison International's composite federal and state statutory tax rate was approximately 40% for all years presented. The lower effective tax rate of 21.5% realized in 2003 was primarily due to the resolution of a FERC rate case at SCE, recording the benefit of favorable settlements of Internal Revenue Service (IRS) audit issues at SCE and the benefits received from low income housing and production tax credits at Edison Capital. The lower effective tax rate of 25.6% realized in 2002 was primarily due to: reestablishing a tax related regulatory asset at SCE due to implementation of the CPUC's URG decision; a favorable adjustment to Edison Capital's cumulative deferred taxes for changes in its effective state tax rate; the benefits received from low income housing and production tax credits at Edison Capital;

recording the benefit of favorable settlements of IRS audits at SCE; and the effect of lower foreign tax rates and permanent reinvestment of earnings of foreign affiliates at EME, offset by foreign losses which were not able to be utilized in the current period.

At December 31, 2003, Edison International and its subsidiaries have federal tax credits of $116 million which expire between 2018 and 2021, California net operating loss carryforwards of $1.2 billion which expire between 2009 and 2011, and California capital loss carryforwards of $88 million that expire in 2005. In addition, EME has foreign loss carryforwards, primarily Australian, of $487 million and $204 million at December 31, 2003 and 2002, respectively, with no expiration date. EME has state loss carryforwards for various states of $168 million and $230 million at December 31, 2003 and 2002, respectively, with various expiration dates.

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

Note 7. Employee Compensation and Benefit Plans

Employee Savings Plan

Edison International has a 401(k) defined contribution savings plan designed to supplement employees' retirement income. The plan received employer contributions of $43 million in 2003, $42 million in 2002 and $40 million in 2001.

Pension Plan and Postretirement Benefits Other Than Pensions

Pension Plan

Defined benefit pension plans (some with cash balance features) cover United States employees meeting minimum service and other requirements. SCE recognizes pension expense for its nonexecutive plan as calculated by the actuarial method used for ratemaking. Certain foreign subsidiaries of EME also participate in their own respective defined benefit pension plans.

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

At December 31, 2003 and December 31, 2002, the accumulated benefit obligations of the executive pension plans, as well as the First Hydro and Edison Mission Limited plans, exceeded the related plan assets at the measurement dates. In accordance with accounting standards, Edison International's balance sheets include an additional minimum liability, with corresponding charges to intangible assets and shareholders' equity (through a charge to accumulated other comprehensive income). The charge to accumulated other comprehensive income would be restored through shareholders' equity in future periods to the extent the fair value of the plan assets exceed the accumulated benefit obligation.

The expected contributions (all by the employer) for United States plans are approximately $47 million for the year ended December 31, 2004. This amount is subject to change based on, among other things, the limits established for federal tax deductibility.

Edison International uses a December 31 measurement date for all of its plans.

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

In millions Year ended December 31,	2003	2002
Change in projected benefit obligation		
Projected benefit obligation at beginning of year	$ 2,694	$ 2,480
Service cost	95	86
Interest cost	170	165
Amendments	—	3
Actuarial loss	139	104
Benefits paid	(139)	(144)
Projected benefit obligation at end of year	$ 2,959	$ 2,694
Accumulated benefit obligation at end of year	$ 2,540	$ 2,288
Change in plan assets		
Fair value of plan assets at beginning of year	$ 2,322	$ 2,768
Actual return on plan assets	605	(316)
Employer contributions	47	14
Benefits paid	(139)	(144)
Fair value of plan assets at end of year	$ 2,835	$ 2,322
Funded status	$ (124)	$ (372)
Unrecognized net loss	144	439
Unrecognized transition obligation	7	12
Unrecognized prior service cost	86	101
Recorded asset	$ 113	$ 180
Additional detail of amounts recognized in balance sheets:		
Intangible asset	$ 4	$ 4
Accumulated other comprehensive income	(22)	(19)
Pension plans with an accumulated benefit obligation in excess of plan assets:		
Projected benefit obligation	$ 162	$ 100
Accumulated benefit obligation	121	76
Fair value of plan assets	25	—
Weighted-average assumptions at end of year:		
Discount rate	6.0%	6.5%
Rate of compensation increase	5.0%	5.0%

Expense components for United States plans are:

In millions Year ended December 31,	2003	2002	2001
Service cost	$ 95	$ 86	$ 82
Interest cost	170	165	164
Expected return on plan assets	(191)	(228)	(255)
Special termination benefits	3	—	13
Net amortization and deferral	36	22	(6)
Expense under accounting standards	113	45	(2)
Regulatory adjustment – deferred	(44)	(18)	39
Total expense recognized	$ 69	$ 27	$ 37
Change in accumulated other comprehensive income	$ (3)	$ (19)	$ —
Weighted-average assumptions:			
Discount rate	6.5%	7.0%	7.25%
Rate of compensation increase	5.0%	5.0%	5.0%
Expected return on plan assets	8.5%	8.5%	8.5%

Asset allocations for United States plans are:

	Target for 2004	December 31, 2003	December 31, 2002
United States equity	45%	46%	45%
Non-United States equity	25%	26%	25%
Private equity	4%	3%	3%
Fixed income	26%	25%	27%

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

In millions Year ended December 31,	2003	2002
Change in projected benefit obligation		
Benefit obligation at beginning of year	$ 66	$ 114
Service cost	4	2
Interest cost	4	8
Actuarial loss (gain)	12	(4)
Curtailment	2	(53)
Plan participants' contribution	1	1
Benefits paid	(4)	(2)
Projected benefit obligation at end of year	$ 85	$ 66
Change in plan assets		
Fair value of plan assets at beginning of year	$ 43	$ 110
Actual return on plan assets	16	(18)
Employer contributions	8	4
Curtailment	—	(51)
Benefits paid	(4)	(2)
Fair value of plan assets at end of year	$ 63	$ 43
Funded status	$ (22)	$ (23)
Unrecognized net loss	20	19
Recorded liability	$ (2)	$ (4)
Pension plans with an accumulated benefit obligation in excess of plan assets:		
Projected benefit obligation	$ 73	$ 58
Accumulated benefit obligation	69	52
Fair value of plan assets	53	37
Weighted-average assumptions at end of year:		
Discount rate	5.50%	5.0% to 5.50%
Rate of compensation increase	3.80% to 4.0%	3.5% to 4.0%

Expense components for foreign plans are:

In millions Year ended December 31,	2003	2002	2001
Service cost	$ 4	$ 2	$ 3
Interest cost	4	8	6
Expected return on plan assets	(5)	(10)	(7)
Curtailment/settlement	1	—	—
Net amortization and deferral	—	15	—
Total expense recognized	$ 4	$ 15	$ 2
Weighted-average assumptions:			
Discount rate	5.0% to 5.5%	4.0% to 6.0%	4.0% to 6.0%
Rate of compensation increase	3.5% to 4.0%	3.5% to 4.0%	3.75% to 4.5%
Expected return on plan assets	7.5% to 8.0%	8.0%	5.75% to 9.0%

Postretirement Benefits Other Than Pensions

Most United States 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 settlement of postretirement employee benefits liability relates to a retirement health care and other benefits plan for represented employees at the Midwest Generation unit (EME's subsidiary that is operating the Illinois plants) that expired on June 15, 2002. In October 2002, Midwest Generation reached an agreement with its union-represented employees on new benefits plans, for the period of January 1, 2003 through June 15, 2006. Midwest Generation continued to provide benefits at the same level as those in the expired agreement until December 31, 2002. The accounting for postretirement benefits liabilities has been determined on the basis of a substantive plan under applicable accounting rules. A substantive plan means that Midwest Generation assumed, for accounting purposes, that it would provide postretirement health care benefits to union-represented employees following conclusion of negotiations to replace the current benefits agreement, even though Midwest Generation had no legal obligation to do so. Under the new agreement, postretirement health care benefits will not be provided. Accordingly, Midwest Generation treated this as a plan termination and recorded a pre-tax gain of $71 million during fourth quarter 2002.

On December 8, 2003, President Bush signed the Medicare Prescription Drug, Improvement and Modernization Act of 2003. The Act authorized a federal subsidy to be provided to plan sponsors for certain prescription drug benefits under Medicare. Edison International has elected to defer accounting for the effects of the Act until the earlier of the issuance of guidance by the Financial Accounting Standards Board on how to account for the Act, or the remeasurement of plan assets and obligations subsequent to January 31, 2004. Accordingly, any measures of the accumulated postretirement benefit obligation or net periodic postretirement benefit expense in the financial statements or this Note do not reflect the effects of the Act on Edison International's plans. Specific authoritative guidance on the accounting for the federal subsidy is pending and that guidance, when issued, could require Edison International to restate previously reported information.

The expected contributions (all by the employer) for the postretirement benefits other than pensions plan are approximately $100 million for the year ended December 31, 2004. This amount is subject to change based on, among other things, the Act referenced above and the impact of any benefit plan amendments.

Edison International uses a December 31 measurement date.

Information on plan assets and benefit obligations is shown below:

In millions Year ended December 31,	2003	2002
Change in benefit obligation		
Benefit obligation at beginning of year	$ 2,171	$ 2,053
Service cost	44	49
Interest cost	126	141
Amendments	(640)	—
Actuarial loss	588	82
Settlement	—	(74)
Benefits paid	(90)	(80)
Benefit obligation at end of year	$ 2,199	$ 2,171
Change in plan assets		
Fair value of plan assets at beginning of year	$ 1,072	$ 1,139
Actual return on assets	292	(148)
Employer contributions	116	161
Benefits paid	(90)	(80)
Fair value of plan assets at end of year	$ 1,390	$ 1,072
Funded status	$ (809)	$ (1,099)
Unrecognized net loss	1,047	715
Unrecognized transition obligation	—	269
Unrecognized prior service cost	(361)	(2)
Recorded liability	$ (123)	$ (117)
Assumed health care cost trend rates:		
Rate assumed for following year	12.0%	9.75%
Ultimate rate	5.0%	5.0%
Year ultimate rate reached	2010	2008
Weighted-average assumptions at end of year:		
Discount rate	6.25%	6.75%

Expense components are:

In millions Year ended December 31,	2003	2002	2001
Service cost	$ 44	$ 49	$ 50
Interest cost	126	141	137
Expected return on plan assets	(89)	(93)	(98)
Special termination benefits	1	—	2
Settlement	—	(71)	—
Net amortization and deferral	40	37	27
Total expense	$ 122	$ 63	$ 118
Assumed health care cost trend rates:			
Current year	9.75%	10.5%	11.0%
Ultimate rate	5.0%	5.0%	5.0%
Year ultimate rate reached	2008	2008	2008
Weighted-average assumptions:			
Discount rate	6.4%	7.25%	7.5%
Expected return on plan assets	8.2%	8.2%	8.2%

Increasing the health care cost trend rate by one percentage point would increase the accumulated obligation as of December 31, 2003 by $317 million and annual aggregate service and interest costs by $29 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated obligation as of December 31, 2003 by $257 million and annual aggregate service and interest costs by $23 million.

Asset allocations are:

	Target for 2004	December 31, 2003	2002
United States equity	64%	64%	64%
Non-United States equity	16%	13%	13%
Fixed income	20%	23%	23%

Description of Investment Strategies for United States Plans

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

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

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

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

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

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

The overall expected long term rate of return on assets assumption is based on the target asset allocation for plan assets, capital markets return forecasts for asset classes employed, and active management excess return expectations. A portion of postretirement benefits other than pensions 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.

Active Management Excess Return Expectations

For asset classes that are actively managed, an excess return premium is added to the capital market return forecasts discussed above.

Long-Term Incentive Plans

Phantom Stock Options

Phantom stock option performance awards were granted through 1999 at EME and Edison Capital as part of the Edison International long-term incentive compensation program for senior management. In August 2000, all outstanding phantom options were exchanged for a combination of cash and stock equivalent units relating to Edison International common stock, in accordance with the EME and Edison Capital affiliate option exchange offers. Compensation expense recorded for the phantom stock options was $5 million in 2003, $3 million in 2002 and $7 million in 2001.

Stock-Based Employee Compensation

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

Under the 1992, 1998 and 2000 plans, options on 14.8 million shares of Edison International common stock are currently outstanding to officers and senior managers.

Each option may be exercised to purchase one share of Edison International common stock and is exercisable at a price equivalent to the fair market value of the underlying stock at the date of grant. Options generally expire 10 years after date of grant and vest over a period of up to five years.

Edison International stock options awarded prior to 2000 include a dividend equivalent feature. Dividend equivalents on stock options issued after 1993 and prior to 2000 are accrued to the extent dividends are declared on Edison International common stock and are subject to reduction unless certain performance criteria are met. Only a portion of the 1999 Edison International stock option awards include a dividend

equivalent feature. The 2003 options include a dividend equivalent feature for the first five years of the option term. Dividend equivalents accumulate without interest.

Options issued after 1997 generally have a four-year vesting period. The special options granted in 2000 vest over five years, in 25% increments beginning in May 2002. Earlier options had a three-year vesting period with one-third of the total award vesting annually. If an option holder retires, dies, is terminated by the company, or is terminated while permanently and totally disabled (qualifying event) during the vesting period, the unvested options will vest on a pro rata basis.

Unvested options of any person who has served in the past on the SCE Management Committee (which was dissolved in 1993) will vest and be exercisable upon a qualifying event. If a qualifying event occurs, the vested options may continue to be exercised within their original terms by the recipient or beneficiary except that in the case of termination by the company where the option holder is not eligible for retirement, vested options are forfeited unless exercised within one year of termination date. If an option holder is terminated other than by a qualifying event, options that had vested as of the prior anniversary date of the grant are forfeited unless exercised within 180 days of the date of termination. All unvested options are forfeited on the date of termination.

The fair value for each option granted, reflecting the basis for the pro forma disclosures in Note 1, was determined on the date of grant using the Black-Scholes option-pricing model. The following assumptions were used in determining fair value through the model:

December 31,	2003	2002	2001
Expected life	**10 years**	7 years – 10 years	7 years – 10 years
Risk-free interest rate	**3.8% to 4.5%**	4.7% to 6.1%	4.7% to 6.1%
Expected dividend yield	**1.8%**	1.8%	3.3%
Expected volatility	**44% to 53%**	18% to 54%	17% to 52%

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

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

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

	Share Options	Exercise Price	Weighted-Average Exercise Price	Weighted-Average Fair Value At Grant	Weighted-Average Remaining Life
Outstanding, Dec. 31, 2000	19,774,672	$14.56–$29.34	$22.24		8 years
Granted	1,001,704	$ 9.10–$15.92	$10.90	$3.88	
Expired	(74,512)	$18.75–$19.35	$18.79		
Forfeited	(11,407,835)	$ 9.15–$29.34	$20.91		
Exercised	—	—	—		
Outstanding, Dec. 31, 2001	9,294,029	$ 9.10–$29.34	$22.45		6 years
Granted	3,450,393	$ 8.90–$19.45	$18.59	$7.88	
Expired	(520,706)	$ 9.57–$29.34	$23.34		
Forfeited	(318,980)	$ 9.10–$28.13	$17.43		
Exercised	(68,444)	$ 9.15–$16.59	$12.45		
Outstanding, Dec. 31, 2002	11,836,292	$ 8.90–$29.25	$21.46		6 years
Granted	3,819,930	$11.88–$19.80	$12.38	$7.31	
Expired	(482,394)	$ 9.57–$29.25	$23.48		
Forfeited	(110,094)	$ 9.57–$18.73	$15.02		
Exercised	(260,481)	$ 9.10–$20.19	$17.67		
Outstanding, Dec. 31, 2003	14,803,253	$ 8.90–$28.94	$19.17		

The number of options exercisable and their weighted-average exercise prices at December 31, 2003, 2002 and 2001 were 7,337,939 at $23.37, 6,475,029 at $23.61 and 5,930,024 at $22.92, respectively.

Other Equity-Based Awards

For the years after 1999, a portion of the executive long-term incentives was awarded in the form of performance shares. Performance shares were awarded in January 2001, January 2002 and January 2003. The performance shares vest December 31, 2003, December 31, 2004 and December 31, 2005, respectively, and are paid out half in shares of Edison International common stock and half in cash. The number of shares that will be paid out from the 2002 and 2003 performance share awards will depend on the performance of Edison International common stock relative to the stock performance of a specific group of peer companies. The 2001 performance share values are accrued ratably over the three-year performance period. The 2002 and 2003 performance shares will be valued based on Edison International's stock performance relative to the stock performance of other such entities.

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

In October 2001, a stock option retention exchange offer was extended, offering holders of Edison International stock options granted in 2000 the opportunity to exchange those options for a lesser number of deferred stock units. The exchange ratio was based on the Black-Scholes value of the options and the stock price at the time the offer was extended. The exchange took place in November 2001; the options that participants elected to exchange were cancelled, and deferred stock units were issued. Approximately three options were cancelled for each deferred stock unit issued. Twenty-five percent of the deferred stock units will vest and be paid in Edison International common stock per year over four years; the first and second vesting dates were in November 2002 and November 2003, respectively. The following assumptions were used in determining fair value through the Black-Scholes option-pricing model: expected life – 8 to 9 years; risk-free interest rate – 5.1%; expected volatility – 52%.

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

Note 8. Jointly Owned Utility Projects

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

The investment in each project as of December 31, 2003 is:

In millions	Investment in Facility	Accumulated Depreciation and Amortization	Ownership Interest
Transmission systems:			
Eldorado	$ 45	$ 11	60%
Pacific Intertie	257	80	50
Generating stations:			
Four Corners Units 4 and 5 (coal)	488	384	48
Mohave (coal)[1]	347	257	56
Palo Verde (nuclear)[2]	1,657	1,460	16
San Onofre (nuclear)[2]	4,297	3,923	75
Total	$7,091	$ 6,115	

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

Note 9. Commitments

Leases

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

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

During 2000, EME entered into a sale-leaseback transaction for power facilities, located in Illinois, with third party lessors for an aggregate purchase price of $1.4 billion.

The lease costs for the power facilities will be levelized over the terms of the power facilities' respective leases. The gain on the sale of the facilities, power plant and equipment has been deferred and is being amortized over the terms of the respective leases.

In connection with EME's acquisition of the Illinois plants, EME assigned the right to purchase the Collins Station in Illinois to third-party lessors. The third-party lessors purchased the Collins Station and entered into leases of the plant with EME. The base lease rent includes both a fixed and variable component; the variable component of which is impacted by movements in defined short-term interest rate indexes. See further discussion in Note 16.

Estimated remaining commitments (the majority of which are related to EME's long-term leases for the Collins, Powerton, Joliet and Homer City power plants) for noncancelable leases at December 31, 2003 are:

Year ended December 31,	In millions
2004	$ 334
2005	374
2006	452
2007	487
2008	484
Thereafter	4,577
Total	$ 6,708

Operating lease expense was $257 million in 2003, $249 million in 2002 and $182 million in 2001.

Nuclear Decommissioning

Effective January 1, 2003, SCE adopted a new accounting standard, Accounting for Asset Retirement Obligations, which requires entities to record the fair value of a liability for a legal ARO in the period in which it is incurred. At that time, SCE adjusted its nuclear decommissioning obligation, increased its unamortized nuclear investment for a new ARO asset, and recorded a regulatory liability to defer the impact on earnings of the change in accounting principle (see further details in "New Accounting Principles" in Note 1). The fair value of decommissioning SCE's nuclear power facilities is $2.1 billion as of December 31, 2003, based on site-specific studies performed in 2001 for San Onofre and Palo Verde. Changes in the estimated costs, timing of decommissioning, or the assumptions underlying these estimates could cause material revisions to the estimated total cost to decommission in the near term. SCE estimates that it will spend approximately $11.4 billion through 2049 to decommission its nuclear facilities. This estimate is based on SCE's current-dollar decommissioning cost methodology used for rate-making purposes, escalated at rates ranging from 0.9% to 10.0% (depending on the cost element) annually. These costs are expected to be funded from independent decommissioning trusts, which effective October 2003 receive contributions of approximately $32 million per year. SCE estimates annual after-tax earnings on the decommissioning funds of 3.7% to 6.5%. If the assumed return on trust assets is not earned, it is probable that additional funds needed for decommissioning will be recoverable through rates.

Decommissioning of San Onofre Unit 1 (shut down in 1992 per CPUC agreement) started in 1999 and will continue through 2008. All of SCE's San Onofre Unit 1 decommissioning costs will be paid from its nuclear decommissioning trust funds. The estimated remaining cost to decommission San Onofre Unit 1 is recorded as an ARO liability ($177 million at December 31, 2003). Total expenditures for the decommissioning of San Onofre Unit 1 were $317 million through December 31, 2003.

SCE plans to decommission its nuclear generating facilities by a prompt removal method authorized by the Nuclear Regulatory Commission. Decommissioning is expected to begin after the plants' operating licenses expire. The operating licenses expire in 2022 for San Onofre Units 2 and 3, and in 2024, 2026 and 2027 for the Palo Verde units. Decommissioning costs, which are recovered through nonbypassable customer rates over the term of each nuclear facility's operating license, are recorded as a component of depreciation expense, with a corresponding credit to the ARO regulatory liability. The earnings impact of amortization of the ARO asset included within the unamortized nuclear investment and accretion of the ARO liability, both created under this new standard, are deferred as increases to the ARO regulatory liability account, with no impact on earnings.

SCE has collected in rates amounts for the future costs of removal of its nuclear assets, and has historically recorded these amounts in accumulated provision for depreciation and decommissioning. However, in accordance with recent Securities and Exchange Commission accounting guidance, the amounts accrued in accumulated provision for depreciation and decommissioning for nuclear decommissioning and costs of removal were reclassified to regulatory liabilities as of December 31, 2002. Upon implementation of the new accounting standard for AROs, SCE reversed the decommissioning amounts collected for assets legally required to be removed and recorded the fair value of this ARO (included in the deferred credits and other liabilities section of the consolidated balance sheet). The cost of removal amounts collected for assets not legally required to be removed remain in regulatory liabilities as of December 31, 2003.

Decommissioning expense under the rate-making method was $118 million in 2003, $73 million in 2002 and $96 million in 2001. The ARO for decommissioning SCE's active nuclear facilities was $1.9 billion at December 31, 2003 and $1.8 billion at December 31, 2002.

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

Trust investments (at fair value) include:

In millions	Maturity Dates	December 31,	2003	2002
Municipal bonds	2004 – 2041		$ 702	$ 486
Stock	–		1,324	1,085
United States government issues	2004 – 2033		363	264
Corporate bonds	2004 – 2038		91	270
Short-term	2004		50	105
Total			$ 2,530	$ 2,210

Note: Maturity dates as of December 31, 2003.

Trust fund earnings (based on specific identification) increase the trust fund balance and the ARO regulatory liability. Net earnings (loss) were $93 million in 2003, $(25) million in 2002 and $13 million in 2001. Proceeds from sales of securities (which are reinvested) were $2.2 billion in 2003, $3.8 billion in 2002 and $3.9 billion in 2001. Gross unrealized holding gains were $677 million and $443 million at December 31, 2003 and 2002, respectively. There were no unrealized holding losses for the years presented. Approximately 91% of the cumulative trust fund contributions were tax-deductible.

Other Commitments

At December 31, 2003, EME had firm commitments to spend approximately $80 million on construction and other capital investments during 2004 through 2006. The construction expenditures primarily relate to the construction of a power plant in New Zealand by Contact Energy. The capital expenditures primarily relate to new plant and equipment at EME's Midwest Generation subsidiary and its Contact Energy project.

At December 31, 2003, EME's Midwest Generation subsidiary was party to a long-term power-purchase contract. The contract requires Midwest Generation to pay a monthly capacity payment and gives Midwest Generation an option to purchase energy at prices based primarily on operations and maintenance and fuel costs.

An EME subsidiary entered into a coal cleaning agreement with an outside party to operate and maintain a coal cleaning plant owned by the EME subsidiary. Under the terms of the agreement, the subsidiary is obligated to reimburse the outside party for the actual costs incurred in the operations and maintenance of the coal cleaning plant, a fixed general and administrative service fee and an operating fee that is dependent on the level of tonnage. The agreement expires on December 31, 2005, with a two-year extension option.

At December 31, 2003, commitments related to these two contracts discussed above are summarized as follows: 2004 – $11 million; 2005 – $10 million; 2006 – $4 million; 2007 – $4 million; and 2008 – $4 million.

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

At December 31, 2003, EME had a contractual commitment to transport natural gas. EME is committed to pay minimum fees under this agreement, which has a term of 15 years.

SCE has power-purchase contracts with certain QFs (cogenerators and small power producers) and other utilities. These contracts provide for capacity payments if a facility meets certain performance obligations and energy payments based on actual power supplied to SCE. There are no requirements to make debt-service payments. In an effort to replace higher-cost contract payments with lower-cost replacement power, SCE has entered into purchased-power settlements to end its contract obligations with certain QFs. The settlements are reported as power-purchase contracts on the balance sheets.

Certain commitments for the years 2004 through 2008 are estimated below:

In millions	2004	2005	2006	2007	2008
Fuel supply contracts	$ 911	$ 814	$ 533	$ 377	$ 204
Gas transportation payments	7	7	7	7	7
Purchased-power capacity payments	682	663	637	637	444

SCE has unconditional purchase obligations for part of a power plant's generating output, as well as firm transmission service from another utility. Minimum payments are based, in part, on the debt-service requirements of the provider, whether or not the plant or transmission line is operable. SCE's minimum commitment under both contracts is approximately $139 million through 2017. The purchased-power contract is expected to provide approximately 5% of current or estimated future operating capacity, and is reported as power-purchase contracts (approximately $28 million). The transmission service contract requires a minimum payment of approximately $6 million a year.

As of December 31, 2003, Edison Capital had outstanding commitments of $68 million to fund energy and infrastructure investments. Prior to funding any commitments, specific contract conditions must be satisfied. At December 31, 2003, Edison Capital had deposited approximately $5 million as collateral for several letters of credit currently outstanding.

EME's Guarantees and Indemnities

Tax Indemnity Agreements

In connection with the sale-leaseback transactions that EME has entered into related to the Collins Station, Powerton and Joliet plants in Illinois and the Homer City facilities in Pennsylvania, EME or one

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

Indemnities Provided as Part of EME's Acquisitions

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

Midwest Generation entered into a supplemental agreement to resolve a dispute regarding interpretation of its reimbursement obligation for asbestos claims under the environmental indemnities set forth in the Illinois plants asset sale agreement. Under this supplemental agreement, Midwest Generation agreed to reimburse the seller 50% of specific existing asbestos claims, less recovery of insurance costs, and agreed to a sharing arrangement for liabilities associated with future asbestos related claims as specified in the agreement. The obligations under this agreement are not subject to a maximum liability. The supplemental agreement has a five-year term with an automatic renewal provision (subject to the right to terminate). Payments are made under this indemnity by a valid claim provided from the seller. At December 31, 2003, Midwest Generation recorded a $10 million liability related to this matter and had made $1 million in payments.

Indemnities Provided Under Asset Sale Agreements

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

Guarantee of 50% of TM Star Fuel Supply Obligations

TM Star was formed for the limited purpose to sell natural gas to the March Point Cogeneration Company, an affiliate through common ownership, under a fuel supply agreement that extends through December 31, 2011. TM Star has entered into fuel purchase contracts with unrelated third parties to meet a portion of the obligations under the fuel supply agreement. EME has guaranteed 50% of TM Star's obligation under the fuel supply agreement to March Point Cogeneration. Due to the nature of the obligation under this guarantee, a maximum potential liability cannot be determined. TM Star has met its

obligations to March Point Cogeneration, and, accordingly, no claims against this guarantee have been made. TM Star was merged into March Point Cogeneration Company effective as of January 16, 2004, and this guarantee terminated by operation of law as of that date.

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 contracts. In addition, subsidiaries of EME have guaranteed the obligations of Kern River Cogeneration Company and Sycamore Cogeneration Company under their project power sales agreements to repay capacity payments to the projects' power purchaser in the event that the projects unilaterally terminate their performance or reduce their electric power producing capability during the term of the power contracts. The obligations under the indemnification agreements as of December 31, 2003, if payment were required, would be $181 million. EME has no reason to believe that any of these projects will either cease operations or reduce its electric power producing capability during the term of its power contract.

Note 10. Contingencies

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

Aircraft Leases

Edison Capital has $63 million invested in three aircraft leased to American Airlines. The independent auditors' opinion on the year-end 2002 financial statements of AMR Corporation, parent company of American Airlines, questions AMR Corporation's ability to continue as a going concern. As disclosed in AMR Corporation's Form 10Q filing for September 30, 2003, there were some improvements made in 2003, such as concessionary agreements with unions and certain other lessors, and reporting operating income of $165 million for the third quarter of 2003. However, significant uncertainty remains and if American Airlines defaults in making its lease payments, the lenders with a security interest in the aircraft or leases may exercise remedies that could lead to a loss of some or all of Edison Capital's investment in the aircraft plus any accrued interest. The total maximum loss exposure to Edison Capital in 2004 is $46 million. A restructure of the lease could also result in a loss of some or all of the investment. At December 31, 2003, American Airlines was current in its lease payments to Edison Capital.

Employee Compensation and Benefit Plans

On July 31, 2003, a federal district court held that the formula used in a cash balance pension plan created by International Business Machine Corporation (IBM) in 1999 violated the age discrimination provisions of the Employee Retirement Income Security Act of 1974. In its decision, the federal district court set forth a standard for cash balance pension plans. This decision, however, conflicts with the decisions from two other federal district courts and with the proposed regulations for cash balance pension plans issued by the IRS in December 2002. On February 12, 2004, the same federal district court ruled that IBM must make back payments to workers covered under this plan. IBM has indicated that it will appeal both decisions to the United States Court of Appeals for the Seventh Circuit. The formula for Edison International's cash balance pension plan does not meet the standard set forth in the federal district court's

July 31, 2003 decision. Edison International cannot predict with certainty the effect of the two IBM decisions on Edison International's cash balance pension plan.

Environmental Remediation

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

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

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

Edison International's recorded estimated minimum liability to remediate its 32 identified sites at SCE (26 sites) and EME (6 sites related to Midwest Generation) is $94 million, $92 million of which is related to SCE. In third quarter 2003, SCE sold certain oil storage and pipeline facilities. This sale caused a reduction in Edison International's recorded estimated minimum environmental liability. 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 $238 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.

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 $71 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 $13 million to $25 million. Recorded costs for 2003 were $14 million.

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

Federal Income Taxes

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

Among the issues raised by the IRS in the 1994 to 1996 audit was Edison Capital's treatment of the EPZ and Dutch electric locomotive leases. Written protests were filed against these deficiency notices, as well as other alleged deficiencies, asserting that the IRS's position misstates material facts, misapplies the law and is incorrect. This matter is now being considered by the Administrative Appeals branch of the IRS. Edison Capital will contest the assessment through administrative appeals and litigation, if necessary, and believes it should prevail in an outcome that will not have a material adverse financial impact.

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

Investigation Regarding Performance Incentives Rewards

SCE is eligible under its CPUC-approved performance-based rate-making (PBR) mechanism to earn rewards or penalties based on its performance in comparison to CPUC-approved standards of reliability, customer satisfaction, and employee safety. SCE received two letters over the last year from 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 to SCE under the PBR provisions for customer satisfaction. SCE is conducting an internal investigation and has determined that some wrongdoing by a number of the service planning employees has occurred. SCE has informed the CPUC of its findings to date, and will continue to inform the CPUC of developments as the investigation progresses. SCE anticipates that, after the investigation is completed, there may be CPUC proceedings to determine whether any portion of past and potential rewards for customer satisfaction should be refunded or disallowed. It also is possible that penalties could be imposed. SCE recorded aggregate customer

satisfaction rewards of $28 million for the years 1998, 1999, and 2000. Potential customer satisfaction rewards aggregating $10 million for 2001 and 2002 are pending before the CPUC and have not been recognized in income by SCE. SCE also had anticipated that it could be eligible for customer satisfaction rewards of about $10 million for 2003. SCE has not yet been able to determine whether or to what extent employee misconduct has compromised the surveys that are the basis for a portion of the awards. Accordingly, SCE cannot predict with certainty the outcome of this matter. SCE plans to complete its investigation as quickly as possible and cooperate fully with the CPUC in taking appropriate remedial action.

Navajo Nation Litigation

In June 1999, the Navajo Nation filed a complaint in the United States District Court for the District of Columbia (D.C. District Court) against Peabody Holding Company (Peabody) and certain of its affiliates, Salt River Project Agricultural Improvement and Power District, and SCE arising out of the coal supply agreement for Mohave. The complaint asserts claims for, among other things, violations of the federal Racketeer Influenced and Corrupt Organizations statute, interference with fiduciary duties and contractual relations, fraudulent misrepresentation by nondisclosure, and various contract-related claims. The complaint claims that the defendants' actions prevented the Navajo Nation from obtaining the full value in royalty rates for the coal. The complaint seeks damages of not less than $600 million, trebling of that amount, and punitive damages of not less than $1 billion, as well as a declaration that Peabody's lease and contract rights to mine coal on Navajo Nation lands should be terminated. SCE joined Peabody's motion to strike the Navajo Nation's complaint. In addition, SCE and other defendants filed motions to dismiss.

Some of the issues included in this case were addressed by the United States Supreme Court in a separate legal proceeding filed by the Navajo Nation in the Court of Federal Claims against the United States Department of Interior. In that action, the Navajo Nation claimed that the Government breached its fiduciary duty concerning negotiations relating to the coal lease involved in the Navajo Nation's lawsuit against SCE and Peabody. On March 4, 2003, the Supreme Court concluded, by majority decision, that there was no breach of a fiduciary duty and that the Navajo Nation did not have a right to relief against the Government. Based on the Supreme Court's analysis, on April 28, 2003, SCE filed a motion to dismiss or, in the alternative, for summary judgment in the D.C. District Court action. The motion remains pending.

The Federal Circuit Court of Appeals, acting on a suggestion on remand filed by the Navajo Nation, held in a October 24, 2003 decision that the Supreme Court's March 24, 2003 decision was focused on three specific statutes or regulations and therefore did not address the question of whether a network of other statutes, treaties and regulations imposed judicially enforceable fiduciary duties on the United States during the time period in question. The Government and the Navajo Nation both filed petitions for rehearing of the October 24, 2003 Court of Appeals decision. Both petitions were denied on March 9, 2004.

SCE cannot predict with certainty the outcome of the 1999 Navajo Nation's complaint against SCE, the impact of the Supreme Court's decision in the Navajo Nation's suit against the Government on this complaint, or the impact of the complaint on the operation of Mohave beyond 2005.

Nuclear Insurance

Federal law limits public liability claims from a nuclear incident to $10.9 billion. SCE and other owners of the San Onofre and Palo Verde Nuclear Generating Stations 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 Nuclear Regulatory

Commission exempted San Onofre Unit 1 from this secondary level, effective June 1994. The maximum deferred premium for each nuclear incident is $101 million per reactor, but not more than $10 million per reactor may be charged in any one year for each incident. Based on its ownership interests, SCE could be required to pay a maximum of $199 million per nuclear incident. However, it would have to pay no more than $20 million per incident in any one year. Such amounts include a 5% surcharge if additional funds are needed to satisfy public liability claims and are subject to adjustment for inflation. If the public liability limit above is insufficient, federal regulations may impose further revenue-raising measures to pay claims, including a possible additional assessment on all licensed reactor operators. The United States Congress has extended the expiration date of the applicable law until December 31, 2004.

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

Spent Nuclear Fuel

Under federal law, the United States 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 has the obligation to begin acceptance of spent nuclear fuel not later than January 31, 1998. However, the DOE did not meet its obligation. It is not certain when the DOE will begin accepting spent nuclear fuel from San Onofre or other nuclear power plants. Extended delays by the DOE have led to the construction of costly alternatives, including 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 Federal Court of Claims seeking damages for DOE's failure to meet its obligation to begin accepting spent nuclear fuel from San Onofre.

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 1, 2 and 3 spent fuel pools and the San Onofre independent spent fuel storage installation. Movement of Unit 1 spent fuel from the Unit 3 spent fuel pool to the independent spent fuel storage installation was completed in late 2003. Movement of Unit 1 spent fuel from the Unit 1 spent fuel pool to the independent spent fuel storage installation is scheduled to be completed by late 2004 and from the Unit 2 spent fuel pool to the independent spent fuel storage installation by late 2005. With these moves, there will be sufficient space in the Unit 2 and 3 spent fuel pools to meet plant requirements through mid-2007 and mid-2008, respectively. In order to maintain a full core off-load capability, SCE is planning to begin moving Unit 2 and 3 spent fuel into the independent spent fuel storage installation by early 2006.

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

Storm Lake

As of December 31, 2003, Edison Capital had an investment of approximately $73 million in Storm Lake Power, a project developed by Enron Wind, a subsidiary of Enron Corporation. As of December 31,

2003, Storm Lake had outstanding loans of approximately $60 million. The lenders claim that Enron's bankruptcy, among other things, is an event of default under the loan agreement and as a result, the debt has been reclassified to long-term debt due within one year. However, the lenders are currently discussing resolution of the defaults with Storm Lake and are not actively pursuing remedies.

Note 11. 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 lease accounting standards. All operating, maintenance, insurance and decommissioning costs are the responsibility of the lessees. The acquisition cost of these facilities was $6.9 billion at both December 31, 2003 and 2002.

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,	2003	2002	2001
Income from leveraged leases	$ 82	$ 105	$ 154
Recomputation due to tax rate change	—	(99)	—
Tax effect of pre-tax income:			
Current	40	138	246
Deferred	(71)	(86)	(307)
Total tax (expense) benefit	(31)	52	(61)
Net income from leveraged leases	$ 51	$ 58	$ 93

The net investment in leveraged leases is:

In millions December 31,	2003	2002
Rentals receivable (net of principal and interest on nonrecourse debt)	$ 3,497	$ 3,496
Unearned income	(1,178)	(1,260)
Investment in leveraged leases	2,319	2,236
Estimated residual value	42	42
Deferred income taxes	(2,055)	(2,044)
Net investment in leveraged leases	$ 306	$ 234

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 energy projects and oil and gas investments and the underlying equity in the net assets was $264 million at December 31, 2003. The difference related to the energy projects is being amortized over the life of the energy projects; the difference related to the oil and gas investments is amortized on a unit-of-production basis over the life of the reserves for the oil and gas projects. Amortization stopped January 1, 2002 in accordance with a new accounting standard.

Summarized financial information of these investments is:

In millions	Year ended December 31,	2003	2002	2001
Revenue		$ 4,068	$ 1,523	$ 3,380
Expenses		3,450	1,312	2,847
Net income		$ 618	$ 211	$ 533

In millions	December 31,	2003	2002
Current assets		$ 1,804	$ 790
Other assets		12,056	5,564
Total assets		$13,860	$ 6,354
Current liabilities		$ 1,239	$ 1,205
Other liabilities		7,930	3,759
Equity		4,691	1,390
Total liabilities and equity		$13,860	$ 6,354

The undistributed earnings of investments accounted for by the equity method were $283 million in 2003 and $275 million in 2002.

Note 12. 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). Its segments are based on Edison International's internal organization. They are separate business units and are managed separately. Edison International evaluates performance based on net income.

SCE is a rate-regulated electric utility that supplies electric energy to a 50,000 square-mile area of central, coastal and Southern California. SCE also produces electricity. EME is engaged in the operation of electric power generation facilities worldwide. EME also conducts energy trading and price risk management activities in markets where power generation facilities are open to competition. Edison Capital is a provider of financial services with investments worldwide.

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

A significant source of revenue from EME's sale of energy and capacity is derived from its Midwest Generation subsidiary's sales to Exelon Generation Company under power purchase agreements terminating in December 2004. Revenue from such sales was $708 million in 2003 and $1.1 billion for each of the years 2002 and 2001. The nonutility power generation segment is responsible for the goodwill reported on the consolidated balance sheets.

Edison International's business segment information is:

In millions	Electric Utility	Nonutility Power Generation	Financial Services	Corporate & Other[1]	Edison International
2003					
Operating revenue	$ 8,853	$ 3,181	$ 88	$ 13	$ 12,135
Depreciation, decommissioning and amortization	882	290	12	—	1,184
Interest and dividend income	100	16	8	3	127
Equity in income from partnerships and unconsolidated subsidiaries – net	—	368	(14)	—	354
Interest expense – net of amounts capitalized	457	498	26	245	1,226
Income tax (benefit) – continuing operations	388	(24)	(38)	(113)	213
Income (loss) from continuing operations	872	28	57	(178)	779
Net income (loss)	922[2]	20	57	(178)	821
Total assets	18,466	12,078	3,418	1,000	34,962
Additions to and acquisition of property and plant	1,161	127	—	—	1,288
2002					
Operating revenue	$ 8,705	$ 2,750	$ 7	$ 26	$ 11,488
Depreciation, decommissioning and amortization	780	247	—	3	1,030
Interest and dividend income	262	18	(1)	8	287
Equity in income from partnerships and unconsolidated subsidiaries – net	—	283	(34)	—	249
Interest expense – net of amounts capitalized	584	452	36	211	1,283
Income tax (benefit) – continuing operations	642	38	(146)	(143)	391
Income (loss) from continuing operations	1,228	82	33	(208)	1,135
Net income (loss)	1,228[2]	25	33	(209)	1,077
Total assets	18,637	11,092	3,479	399	33,607
Additions to and acquisition of property and plant	1,046	554	1	(11)	1,590
2001					
Operating revenue	$ 8,120	$ 2,594	$ 202	$ 146	$ 11,062
Depreciation, decommissioning and amortization	681	273	17	2	973
Interest and dividend income	215	35	19	13	282
Equity in income from partnerships and unconsolidated subsidiaries – net	—	374	(31)	—	343
Interest expense – net of amounts capitalized	785	547	64	186	1,582
Income tax (benefit) – continuing operations	1,658	96	(24)	(83)	1,647
Income (loss) from continuing operations	2,386	113	84	(181)	2,402
Net income (loss)	2,386[2]	(1,121)	84	(314)	1,035
Total assets	22,453	10,730	3,736	(145)	36,774
Additions to and acquisition of property and plant	688	242	3	—	933

(1) Includes amounts from nonutility subsidiaries (including MEHC), as well as Edison International (parent) not significant as a reportable segment

(2) Net income available for common stock.

The net income reported for electric utility includes earnings from discontinued operations of $50 million for 2003. The net income (loss) reported for nonutility power generation includes earnings (loss) from discontinued operations of $1 million for 2003, $(57) million for 2002 and $(1.2) billion for 2001. The net loss reported for corporate and other includes loss from discontinued operations of $(1) million for 2002 and $(133) million for 2001.

Geographic Information

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

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

In millions Year ended December 31,	2003	2002	2001
Revenue			
United States	$ 10,533	$ 10,331	$ 10,141
Foreign countries:			
United Kingdom	371	317	324
Australia	234	204	166
New Zealand	756	493	294
Netherlands	5	(24)	—
South Africa	6	(16)	—
Switzerland	62	56	—
Other	168	127	137
Total	$ 12,135	$ 11,488	$ 11,062

In millions December 31,	2003	2002
Assets		
United States[1]	$ 25,602	$ 25,743
Foreign countries:		
United Kingdom[1]	1,630	1,680
Australia	1,989	1,565
New Zealand	2,640	1,738
Netherlands	562	556
South Africa	642	646
Switzerland	545	483
Other	1,352	1,196
Total	$ 34,962	$ 33,607

(1) Includes assets of discontinued operations.

Note 13. Acquisitions and Dispositions

Acquisitions

On July 17, 2003, SCE signed an option agreement with Sequoia Generating LLC, a subsidiary of InterGen, to acquire Mountainview Power Company LLC, the owner of a new power plant currently being developed in Redlands, California. This acquisition requires regulatory approval from both the CPUC and the FERC. On December 18, 2003, the CPUC approved SCE's application proposing a power-purchase agreement between SCE and Mountainview Power Company LLC. On February 25, 2004, the FERC granted conditional approval of the power-purchase agreement. On February 28, 2004, SCE exercised its option to purchase Mountainview. The purchase is expected to close in March 2004. SCE will recommence full construction of the project once the purchase closes.

On March 3, 2003, Contact Energy, EME's 51% owned subsidiary, completed a transaction with NGC Holdings Ltd. to acquire the Taranaki combined cycle power station and related interests. Consideration for the Taranaki station consisted of a cash payment of approximately $275 million, which was initially financed with bridge loan facilities. The bridge loan facilities were subsequently repaid with proceeds from Contact Energy's issuance of long-term United States dollar denominated notes. The Taranaki station is a 357 MW combined cycle, natural gas-fired plant located near Stratford, New Zealand.

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

In February 2001, EME completed the acquisition of a 50% interest in CBK Power Co. Ltd. for $20 million. CBK Power has entered into a 25-year build-rehabilitate-transfer-and-operate agreement with National Power Corporation related to a hydroelectric project located in the Philippines. Financing for this $460 million project includes equity commitments of $117 million (EME's share is approximately $59 million) and debt financing, which is in place for the remainder of the cost of this project. The indebtedness incurred by CBK Power is nonrecourse to EME.

Dispositions

On January 7, 2004, EME completed the sale of 100% of its stock of Edison Mission Energy Oil & Gas, which in turn holds minority interests in Four Star Oil & Gas. Proceeds from the sale were approximately $100 million. EME expects to record a pre-tax gain on the sale of approximately $47 million during the first quarter of 2004.

In 2003, SCE completed the sale of certain oil storage and pipeline facilities. See additional discussion in Note 15.

On December 31, 2003, EME agreed to sell its 50% partnership interest in its Brooklyn Navy Yard project to a third party. Completion of the sale, currently expected in the first quarter of 2004, is subject to closing conditions, including obtaining regulatory approval. Proceeds from the sale are expected to be

approximately $42 million. EME recorded an impairment charge of $53 million during the fourth quarter of 2003 related to the planned disposition of this investment.

On November 21, 2003, Gordonsville Energy Limited Partnership, in which EME owns a 50% interest, completed the sale of the Gordonsville cogeneration facility. Proceeds from the sale, including distribution of a debt service reserve fund, were $36 million. In second quarter 2003, EME recorded an impairment charge of $6 million related to the planned disposition of this investment.

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

During 2001, EME completed the sales of its interests in the Nevada Sun-Peak project (50%), Saguaro project (50%) and Hopewell project (25%) for a total gain on sale of $45 million ($24 million after tax). In addition, EME entered into agreements, subject to obtaining consents from third parties and other conditions, for the sale of its interests in the Commonwealth Atlantic, Gordonsville, EcoEléctrica, Harbor and James River projects. During 2001, EME recorded asset impairment charges of $34 million related to these projects based on the expected sales proceeds.

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

In December 2001, EME completed the sale of the Ferrybridge and Fiddler's Ferry coal-fired power plants located in the United Kingdom. See additional discussion in Note 15.

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

Note 14. Asset Impairments

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

During 2003, EME recorded asset impairment charges of $304 million, consisting of $245 million related to eight small peaking plants in Illinois (owned by Midwest Generation) and $53 million and $6 million to write-down the estimated net proceeds from the planned sale of its interests in the Brooklyn Navy Yard and Gordonsville projects, respectively (see Note 13). The impairment charge related to the peaking plants resulted from a revised long-term outlook for capacity revenue from the peaking plants due to a number of factors, including higher long-term natural gas prices and a current generation overcapacity. The book value of these assets was written down from $286 million to an estimated fair market value of $41 million. The estimated fair value was determined based on discounting estimated future cash flows using a 17.5% discount rate.

During 2002, EME recorded asset impairment charges of $86 million, consisting of $61 million related to the write-off of capitalized costs associated with the termination of equipment purchase contracts with

Siemens Westinghouse and $25 million related to the write-off of capitalized costs associated with the suspension of the Powerton Station selective catalytic reduction major capital environmental improvements project at the Illinois plants.

Note 15. Discontinued Operations

On July 10, 2003, the CPUC approved SCE's sale of certain oil storage and pipeline facilities to Pacific Terminals LLC for $158 million. In third quarter 2003, SCE recorded a $44 million after-tax gain to shareholders.

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

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

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

In 2003, the results of SCE's oil storage and pipeline facilities unit have been accounted for as a discontinued operation in accordance with an accounting standard related to the impairment and disposal of long-lived assets. Due to immateriality, the results of this unit for prior years have not been restated and are reflected as part of continuing operations.

In 2002, the results of the Lakeland project are reflected as discontinued operations in the consolidated financial statements in accordance with an accounting standard related to the impairment and disposal of long-lived assets. Due to immateriality, the results of the Lakeland project in 2001 have not been restated and are reflected as part of continuing operations.

For all years presented, the results of the Fiddler's Ferry and Ferrybridge coal stations and Edison Enterprises subsidiaries sold during 2001 have been reflected as discontinued operations in the consolidated financial statements in accordance with an accounting standard related to the impairment and disposal of long-lived assets. Unless otherwise discussed above, the consolidated financial statements have been restated to conform to the discontinued operations presentation for all years presented.

Revenue from discontinued operations was $21 million in 2003, $74 million in 2002 and $748 million in 2001. The before-tax earnings (losses) of the discontinued operations were $84 million in 2003, $(74) million in 2002 and $(2.2) billion in 2001.

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

In millions December 31,	2003	2002
Assets		
Receivables – net	$ —	$ 1
Other	5	9
Total current assets	5	10
Utility plant – net	—	5
Nonutility property – net	—	51
Other noncurrent assets	11	57
Total assets	$ 16	$ 123
Liabilities		
Accounts payable and accrued liabilities	$ 3	$ 23
Noncurrent liabilities	10	49
Total liabilities	$ 13	$ 72

Note 16. Subsequent Event

On March 10, 2004, EME's subsidiary, Midwest Generation, agreed in principle with the lease equity investor to terminate the Collins Station lease. The agreement in principle sets forth specified conditions required for the termination, including Midwest Generation successfully borrowing funds to finance the repayment of Collins Station lease debt of $774 million and settlement of Midwest Generation's termination liability with the lease equity investor. There is no assurance that the agreement in principle will result in termination of the Collins Station lease. If the termination occurs, Midwest Generation will take title to the Collins Station and, subject to its contractual obligation to Exelon Generation, plans to subsequently abandon the Collins Station or sell it to a third party.

If Midwest Generation completes the lease termination and subsequently abandons the Collins Station, EME expects to record a pre-tax loss of approximately $1 billion (approximately $620 million after tax). This loss will reduce EME's net worth (using December 31, 2003) from $1.9 billion to approximately $1.3 billion. To avoid the possibility of covenant defaults which could arise from a decline in net worth, EME plans to take the following actions before or simultaneously with the Collins Station lease termination:

- replace its $145 million corporate credit facility with a new secured credit facility;
- repay the $28 million due under the Coal and Capex facility (guaranteed by EME); and

- eliminate or modify the net worth covenant in its guaranty of the Powerton-Joliet lease.

If Midwest Generation completes the termination of the Collins Station lease followed by abandonment or sale to a third party, EME anticipates that the termination payment would result in a substantial income tax deduction. Because of these arrangements, EME does not expect that termination of the Collins Station lease will have a material adverse effect on its liquidity. If the lease termination does not occur, the terms of the lease will remain in effect and Midwest Generation will seek to restructure the lease with the lease equity investor.

In millions, except per-share amounts	2003 Total	Fourth	Third	Second	First
Operating revenue	$ 12,135	$ 2,654	$ 3,833	$ 3,125	$ 2,523
Operating income	1,791	331	925	224	311
Income from continuing operations	779	193	500	23	63
Income from discontinued operations – net	51	3	44	1	3
Cumulative effect of accounting change – net	(9)	—	—	—	(9)
Net income	821	196	544	24	57
Basic earnings (loss) per share:					
Continuing operations	2.39	0.59	1.53	0.07	0.19
Discontinued operations	0.16	0.01	0.14	—	0.01
Cumulative effect of accounting change	(0.03)	—	—	—	(0.03)
Total	2.52	0.60	1.67	0.07	0.17
Diluted earnings (loss) per share:					
Continuing operations	2.37	0.59	1.52	0.07	0.19
Discontinued operations	0.16	0.01	0.13	—	0.01
Cumulative effect of accounting change	(0.03)	—	—	—	(0.03)
Total	2.50	0.60	1.65	0.07	0.17
Dividends declared per share	0.20	0.20	—	—	—
Common stock prices:					
High	22.07	22.07	19.65	17.12	14.00
Low	10.57	19.10	15.81	13.30	10.57
Close	21.93	21.93	19.10	16.43	13.69

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

Dollars in millions, except per-share amounts	2003	2002	2001	2000	1999
Edison International and Subsidiaries					
Operating revenue	$ 12,135	$ 11,488	$ 11,062	$ 10,424	$ 8,932
Operating expenses	$ 10,344	$ 9,116	$ 5,980	$ 12,499	$ 7,359
Income (loss) from continuing operations	$ 779	$ 1,135	$ 2,402	$ (1,939)	$ 681
Net income (loss)	$ 821	$ 1,077	$ 1,035	$ (1,943)	$ 623
Weighted-average shares of common stock outstanding (in millions)	326	326	326	333	348
Basic earnings per share:					
Continuing operations	$ 2.39	$ 3.49	$ 7.37	$ (5.83)	$ 1.96
Discontinued operations	$ 0.16	$ (0.18)	$ (4.19)	$ (0.01)	$ (0.17)
Cumulative effect of accounting change	$ (0.03)	$ —	$ —	$ —	$ —
Total	$ 2.52	$ 3.31	$ 3.18	$ (5.84)	$ 1.79
Diluted earnings per share	$ 2.50	$ 3.28	$ 3.17	$ (5.84)	$ 1.79
Dividends declared per share	$ 0.20	$ —	$ —	$ 0.84	$ 1.08
Book value per share at year-end	$ 16.52	$ 13.62	$ 10.04	$ 7.43	$ 15.01
Market value per share at year-end	$ 21.93	$ 11.85	$ 15.10	$ 15.625	$ 26.187
Rate of return on common equity	17.1%	27.0%	58.0%	(41.0)%	12.2%
Price/earnings ratio	8.7	3.6	4.7	(2.7)	14.6
Ratio of earnings to fixed charges	1.65	2.08	3.21	*	1.99
Assets	$ 34,962	$ 33,607	$ 36,774	$ 35,100	$ 36,229
Long-term debt	$ 11,787	$ 11,578	$ 12,674	$ 12,150	$ 13,391
Common shareholders' equity	$ 5,383	$ 4,437	$ 3,272	$ 2,420	$ 5,211
Preferred stock subject to mandatory redemption	$ 141	$ 147	$ 151	$ 256	$ 256
Company-obligated mandatorily redeemable securities of subsidiaries holding solely parent company debentures	$ —	$ 951	$ 949	$ 949	$ 948
Retained earnings	$ 3,466	$ 2,711	$ 1,634	$ 599	$ 3,079
Southern California Edison Company					
Operating revenue	$ 8,854	$ 8,706	$ 8,126	$ 7,870	$ 7,548
Net income (loss) available for common stock	$ 922	$ 1,228	$ 2,386	$ (2,050)	$ 484
Basic earnings (loss) per Edison International common share	$ 2.83	$ 3.77	$ 7.32	$ (6.16)	$ 1.39
Rate of return on common equity	20.2%	31.8%	311.0%	(67.6)%	15.2%
Peak demand in megawatts (MW)	20,136	18,821	17,890	19,757	19,122
Generation capacity at peak (MW)	9,861	9,767	9,802	9,886	10,431
Kilowatt-hour deliveries (in millions)	93,826	79,693	78,524	84,430	78,602
Customers (in millions)	4.60	4.53	4.47	4.42	4.36
Full-time employees	12,698	12,113	11,663	12,593	13,040
Edison Mission Energy					
Revenue	$ 3,181	$ 2,750	$ 2,594	$ 2,294	$ 1,083
Income from continuing operations	$ 28	$ 82	$ 113	$ 101	$ 109
Net income (loss)	$ 20	$ 25	$ (1,121)	$ 125	$ 130
Assets	$ 12,078	$ 11,092	$ 10,730	$ 15,017	$ 15,534
Rate of return on common equity	1.1%	1.5%	(46.9)%	4.3%	8.1%
Ownership in operating projects (MW)	18,733	18,688	19,019	22,759	22,037
Full-time employees	2,610	2,662	3,021	3,391	3,245
Edison Capital					
Revenue	$ 88	$ 7	$ 202	$ 274	$ 282
Net income	$ 57	$ 33	$ 84	$ 135	$ 129
Assets	$ 3,418	$ 3,479	$ 3,736	$ 3,713	$ 2,712
Rate of return on common equity	7.5%	4.2%	11.9%	22.9%	27.0%
Full-time employees	62	61	66	119	115

* less than 1.00

During 2003, SCE sold certain oil storage and pipeline facilities. During 2002, EME recorded an impairment charge related to its Lakeland plant and during 2001, EME sold its generating plants located in the United Kingdom and Edison Enterprises sold the majority of its assets. Amounts presented in this table have been restated to reflect continuing operations unless stated otherwise. See Note 15, Discontinued Operations, for further discussion.

[INTENTIONALLY LEFT BLANK]

BOARD OF DIRECTORS*

John E. Bryson [1]
Chairman of the Board,
President and Chief Executive Officer,
Edison International;
Chairman of the Board,
Southern California Edison Company;
Chairman of the Board,
Edison Capital
A director since 1990†

Bradford M. Freeman [1,4,5]
Founding Partner,
Freeman Spogli & Co.
(private investment company)
Los Angeles, California
A director since 2002

Bruce Karatz [2,5]
Chairman and Chief Executive Officer,
KB Home (homebuilding)
Los Angeles, California
A director since 2002

Luis G. Nogales [2,4]
Managing Partner,
Nogales Investors, LLC
(private equity investment company)
Los Angeles, California
A director since 1993

Ronald L. Olson [3,4]
Senior Partner,
Munger, Tolles and Olson (law firm)
Los Angeles, California
A director since 1995

James M. Rosser [2,3,5]
President,
California State University, Los Angeles
Los Angeles, California
A director since 1985

Richard T. Schlosberg, III [1,5]
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]
Robert H. Smith Investments
and Consulting
(banking and financial-related
consulting services)
Pasadena, California
A director since 1987

Thomas C. Sutton [1,2,3]
Chairman of the Board and
Chief Executive Officer,
Pacific Life Insurance Company
Newport Beach, California
A director since 1995

Daniel M. Tellep [1,4 **]
Retired Chairman of the Board,
Lockheed Martin Corporation
(aerospace industry)
Saratoga, California
A director since 1992

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

* Except as otherwise indicated, service includes combined Edison International and Southern California Edison Company Board memberships

** Retiring May 20, 2004

† For Southern California Edison Company, a director from 1990-1999; 2003 to present

MANAGEMENT TEAM

Edison International

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

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

Bryant C. Danner
Executive Vice President and General Counsel

Mahvash Yazdi
Senior Vice President, Business Integration, and Chief Information Officer

Diane L. Featherstone
Vice President and General Auditor

Polly L. Gault
Vice President, Public Affairs, Washington, D.C.

Jo Ann Goddard
Vice President, Investor Relations

Frederick J. Grigsby, Jr.
Vice President, Human Resources and Labor Relations

Thomas M. Noonan
Vice President and Controller

Barbara J. Parsky
Vice President, Corporate Communications

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

Anthony L. Smith
Vice President, Tax

Southern California Edison Company

John E. Bryson
Chairman of the Board

Alan J. Fohrer
Chief Executive Officer

Robert G. Foster
President

Harold B. Ray
Executive Vice President, Generation

Pamela A. Bass
Senior Vice President, Customer Service

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

Stephen E. Pickett
Senior Vice President and General Counsel

Richard M. Rosenblum
Senior Vice President, Transmission and Distribution

W. James Scilacci
Senior Vice President and Chief Financial Officer

Mahvash Yazdi
Senior Vice President, Business Integration, and Chief Information Officer

Emiko Banfield
Vice President, Shared Services

Robert C. Boada
Vice President and Treasurer

William L. Bryan
Vice President, Major Customer Division

Jodi M. Collins
Vice President, Information Technology

Diane L. Featherstone
Vice President and General Auditor

Bruce C. Foster
Vice President, Regulatory Operations

Polly L. Gault
Vice President, Public Affairs, Washington, D.C.

A. Larry Grant
Vice President, Power Delivery

Frederick J. Grigsby, Jr.
Vice President, Human Resources and Labor Relations

Harry B. Hutchison
Vice President, Customer Service Operations

James A. Kelly
Vice President, Engineering and Technical Services

Russ W. Krieger
Vice President, Power Production

Thomas M. Noonan
Vice President and Controller

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

Barbara J. Parsky
Vice President, Corporate Communications

Pedro J. Pizarro
Vice President, Power Procurement, and General Manager, Edison Carrier Solutions

Frank J. Quevedo
Vice President, Equal Opportunity

Anthony L. Smith
Vice President, Tax

Joseph J. Wambold
Vice President, Nuclear Generation

Beverly P. Ryder
Corporate Secretary

Edison Mission Energy

Thomas R. McDaniel
Chairman of the Board, President and Chief Executive Officer

Robert M. Edgell
Executive Vice President and General Manager, Asia Pacific

Ronald L. Litzinger
Senior Vice President and Chief Technical Officer

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

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

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

Raymond W. Vickers
Senior Vice President and General Counsel

Edison Capital

John E. Bryson
Chairman of the Board

Thomas R. McDaniel
Chief Executive Officer

Ashraf T. Dajani
President and Chief Operating Officer

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

Phillip B. Dandridge
Vice President and Chief Financial Officer

SHAREHOLDER INFORMATION

ANNUAL MEETING

The annual meeting of shareholders will be held on Thursday, May 20, 2004, at 10:00 a.m., Pacific Daylight Time, at the Hyatt Regency Long Beach, 200 South Pine Avenue, Long Beach, California 90802.

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

Preferred Securities and Preferred Stock

The EIX Trust I and II preferred securities are listed on the New York Stock Exchange under the ticker symbols EIX PrA for the 7.875% QUIPS Series A and EIX PrB for the 8.60% QUIPS Series B. Previous day's closing prices, when traded, are listed in the daily newspapers in the New York Stock Exchange composite table.

Southern California Edison Company's 4.08%, 4.24%, 4.32% and 4.78% Series of cumulative preferred stock are listed on the American and Pacific stock exchanges under the ticker symbol SCE. Previous day's closing prices, when traded, are listed in the daily newspapers in the American Stock Exchange composite table. The 6.05% and 7.23% Series of the $100 cumulative preferred stock are not listed and are traded over-the-counter. The preferred securities of Mission Capital, L.P., an affiliate of Edison Mission Energy, are listed on the New York Stock Exchange under the ticker symbol ME PrA for the 9.875% Series A and ME PrB for the 8.50% Series B.

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 stocks. 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;
- direct debit of optional cash for dividend reinvestment;
- Edison International's Dividend Reinvestment and Stock Purchase Plan, including enrollments, withdrawals, terminations, transfers, sales, duplicate statements; and
- requests for access to online account information.

Inquiries may also be directed to:

Mail

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

Fax

(651) 450-4033

Email

stocktransfer@wellsfargo.com

Web Address

www.edisoninvestor.com

Online account information:

www.shareowneronline.com

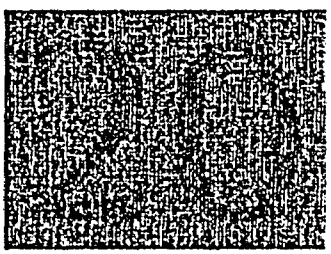
DIVIDEND REINVESTMENT AND ELECTRONIC TRANSFER

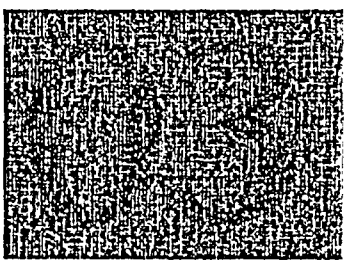
A prospectus and enrollment forms for Edison International's Common Stock Dividend Reinvestment and Stock Purchase Plan are available from Wells Fargo Shareowner Services upon request.

EDISON
INTERNATIONAL®

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

El Paso Electric

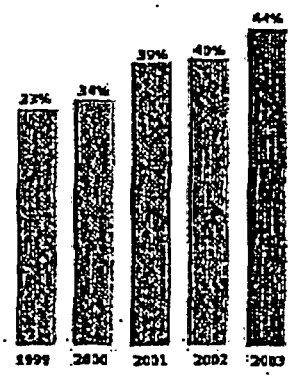




Annual Report

2003 Performance Highlights

COMMON STOCK EQUITY
(percent of capitalization)



Financial ($000)	2001
Operating Revenues (net of energy expenses)	$498,669(a)
Retail Base Revenues	$435,276
Economy Sales (net of fuel)	$54,492
Net Income (applicable to common stock)	$63,659
Total Assets	$1,644,439

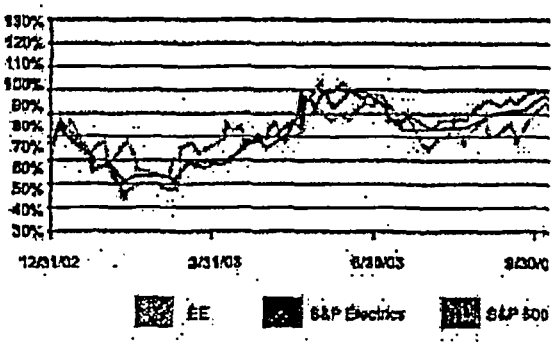
Common Stock Data	
Earnings Per Share (diluted weighted average)	$1.23
Market Price Per Share (year-end close)	$14.50
Book Value Per Share	$8.96
Market To Book Ratio	162%
Weighted Average Number of Common Shares Outstanding	51,722,351
Number of Registered Holders	5,580

**2002 data includes effects of $15.5 million FERC settlements*
(a) Operating Re venues (net of energy expenses) for 2001 and 2002 changed from the 2002 presen
(b) Included in 2003 net income and diluted earnings per share is a cumulative effect of an a ccountir $0.81 per diluted share .

Cumulative Share Repurchases
(in millions)

Cumulative Debt Repurchases and Redemptions
(in millions)

Relative Price Performance El Paso Electric vs. S&P Electric and S&P 500 Utilites Indices 12/31/02- 12/31/03



Statements in this document, other than statements of historical information, a are made pursuant to the safe harbor provisions of the Private Securities Litiga forward-looking statements, as well as other oral and written forward-looking s El Paso Electric (EPE) from time to time, including statements contained in EP Exchange Commission and its reports to shareholders, involve known and unk may cause EPE's actual results in future periods to differ materially from those statements. Please refer to EPE's 10-K for fiscal year ended December 31, 20 for a detailed discussion of these risks and uncertainties. EPE cautions that th not exclusive. EPE does not undertake to update any forward-looking statemei time by or on behalf of EPE, except as required by law.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Dear Shareholders:

We are pleased to report 2003 was a positive year for El Paso Electric (EPE) on several fronts. Our robust cash flow supported ongoing improvement in financial fundamentals; the stock price performed well, tracking market indices and returning to historic growth patterns; we experienced significant improvement in the wholesale market; and our customer growth in the region continued at an above-average pace reflecting the inherent strength in our core business. We also resc significant regulatory uncertainties at the federal and state levels, and on the operations side, the Palo Verde Nuclear Generating Station continued its exceptional performance.

During 2003, our free cash flow contributed to further improvement in our financial profile by reducing the leverage in balance sheet and allowing us to complete the third of three share repurchase programs. EPE reduced its debt by approxim $39.4 million in 2003, which decreased annual fixed charges on an ongoing basis by approximately $3.2 million per year. early 2004 EPE repurchased an additional $6 million in First Mortgage Bonds and will continue to strive towards attaining more balanced capital structure to reduce financial risk, improve credit quality and enhance our financial flexibility. EPE repurchased approximately 2.1 million common shares in 2003, completing its 15 million share repurchase program initiat 1999 at a purchase price of approximately $171 million. In February 2004, our Board of Directors authorized an additiona stock repurchase program of up to two million shares. EPE remains committed to creating maximum value for its shareho by pursuing its stock repurchase program when economically viable, strengthening its balance sheet, increasing its operati efficiencies, and seeking additional opportunities in the wholesale market, including Mexico.

As a result of EPE's conservative financial policies, we have been able to significantly improve the Company's capital structure. At year-end EPE posted a common stock equity ratio of 44 percent, which marks a dramatic improvement from June 30, 1996 level of 19 percent.

EPE stock tracked the performance of the utility sector and produced a one-year return of 21.36 percent, with a year-en closing stock price of $13.35. Over the past five-year period, EPE stock has significantly outperformed the utilities indices the broader market, with a total return of 52.57 percent from 1998 to 2003. In comparison, the Dow Jones Industrial Aver Total Return Index posted a gain of 24.79 percent, while the S & P Electric Utilities Index and the Dow Jones Utilities Ind have posted five-year total returns of 13.18 percent and 3.56 percent, respectively. The S & P 500 Utilities Total Return In experienced an 11.88 percent decline from 1998 to 2003.

In 2003, EPE reported diluted earnings per share of $0.64, before the cumulative effect of implementing an accounting change related to SFAS 143 "Accounting for Asset Retirement Obligations" and before the impact of a one-time Custome Information System (CIS) project impairment loss. EPE's earnings were affected by the expiration of two long-term whole contracts and a ruling by the Public Utility Commission of Texas (PUCT) on EPE's fuel reconciliation case. This impact w partially offset by increased economy kWh sales and profit margins, higher retail sales, decreased loss on extinguishment debt, decreased MiraSol operating loss, and by the 2002 accrual for the Federal Energy Regulatory Commission (FERC) settlements with no comparable amount in 2003. EPE's improving financial fundamentals continue to be recognized by the financial community. In August 2003, Moody's Investor Service affirmed EPE's investment grade credit rating and change business outlook from negative to stable. Standard & Poor's continues to rate EPE as an investment grade company with a stable outlook.

Although EPE experienced the full-year impact of two wholesale power contracts that expired in 2002, it was successfu finding other opportunities in the wholesale market. Economy kWh sales increased 29.5 percent over 2002 levels and EPE profit margins on economy sales contributed $0.13 per share to earnings in 2003. While we benefited from improved conditions in the western wholesale power market in 2003, and will continue to aggressively pursue these opportunities, previous years' experiences have demonstrated the inherent volatility in this environment.

EPE provided some power to Mexico for peaking needs during the summer of 2003, marking the 16th consecutive yea we have sold power to the Comisión Federal de Electricidad (CFE). We continue to work closely with the CFE regarding long-term energy requirements and infrastructure needs.

EPE exhibited a strong customer growth rate of 2.7 percent during 2003. EPE's residential, commercial and industrial customer classes experienced increased sales growth as the regional economy appeared to show signs of improving during fourth quarter. Our residential segment posted annual growth in kWh sales of 3.3 percent. Overall, EPE posted retail sales growth of 2 percent for the year, which is in the range of our historic level of sales. Growth in retail sales and our expandi customer base enabled us to achieve a record native system peak of 1,308 MW in 2003, surpassing the previous record of 1,282 MW set in the summer of 2002. We also reached a record total system peak demand of 1,546 MW during the year, which represents a 2.5 percent increase over the previous record of 1,509 MW. On July 23, 2003, the FERC approved settlement agreement among EPE, the FERC staff and certain California intervenors, closing the review of EPE's involve in the western power markets in 2000 and 2001. The U.S. Commodity Futures Trading Commission also notified the Com that it has closed its investigation into EPE's western power market activities during the 2000-2001 time period. The resol of these matters allows us to refocus our efforts on our core business of providing electric service to our customers.

A number of important state regulatory events also occurred during 2003 in both Texas and New Mexico. On April 8, the Governor of New Mexico signed the repeal of the New Mexico Electric Utility Industry Restructuring Act of 1999,

effectively ending a move toward retail competition. EPE's business in New Mexico will continue as a traditional cost-of-service regulated utility.

In January 2004, we reached a unanimous settlement regarding base and fuel rates in New Mexico. The agreement call: a one percent reduction in base rates followed by a three-year base rate freeze, a slight increase in the Palo Verde fuel-sha mechanism which benefits our New Mexico customers, and a reconciliation of all New Mexico fuel costs through May 31 2004. The settlement, which is expected to be approved by the New Mexico Public Regulation Commission (NMPRC) by 2004, provides continued rate stability in our New Mexico service territory which comprises 22 percent of our retail busin

In March 2004, the PUCT ruled on EPE's petition to reconcile fuel costs for the period from January 1999 through December 2001. EPE had filed a request to recover $15.8 million, before interest, from its Texas customers because of fue undercollections from 1999 to 2001. The PUCT disallowed approximately $4.5 million of Texas jurisdictional fuel expens before interest, the majority of which the PUCT characterized as imputed capacity charges. The PUCT decided all other material contested issues in favor of EPE. The disallowance by the PUCT represented approximately 1.6 percent of the mc than $277 million in fuel revenues at issue in the case. The remainder of the undercollections, approximately $10.9 millior plus interest, was deemed fully recoverable fuel expenses. After a written order has been issued by the PUCT, the decision be subject to appeal by various affected parties.

Finally, in December 2003, the PUCT initiated a project to evaluate the readiness of EPE's service area for retail competition. On March 4, 2004, the staff of the PUCT held a workshop in El Paso to receive information from interested parties on how to proceed with introducing retail electric competition in the area. EPE presented an overview of the Comp transmission and distribution operations along with specific information on the absence of various infrastructure and operational conditions that were contemplated by enabling legislation as preconditions to competition. Those attending the workshop generally urged the PUCT staff to address the issue of competition in the El Paso area slowly and deliberately, making sure the right conditions exist for successful electric retail competition.

On the operations side, the Palo Verde Nuclear Generating Station continued its record-setting performance and was or again the nation's largest power producer in 2003, with an output of 28.6 billion kWh. This marks the twelfth consecutive that Palo Verde has achieved this distinction. In addition, in February 2003, the Nuclear Regulatory Commission (NRC) completed its end-of-cycle plant performance assessment. The NRC found that "overall, Palo Verde operated in a manner preserved public health and safety and fully met all cornerstone objectives."

Several milestones were reached during Palo Verde Unit 2's 79-day refueling outage in 2003, including the replacemen two 800-ton steam generators and work on the low-pressure turbine rotors that should ultimately contribute to an increase capacity for Unit 2. The plant continues to provide approximately 50 percent of our energy at a cost well below that of nev natural gas-fired generation.

EPE and its Board of Directors are committed to ensuring all business conducted by the Company and its employees is performed honestly and in strict adherence to the highest ethical practices. In response to passage of the Sarbanes-Oxley A EPE has formalized its existing practices and is demonstrably committed to full compliance with the requirements of the A Our standards of corporate governance meet the requirements of the Act, and we will continue our commitment to the higl standards in all our business dealings. Detailed information on our corporate governance standards and policies can be fou on our website at www.epelectric.com.

EPE and its employees are not only committed to serving our customers with safe, efficient and reliable electric service also have a long-standing dedication to being a good corporate citizen and making the communities we serve better places which to live and work. During 2003, EPE employees volunteered more than 13,000 hours toward community service, surpassed our United Way goals, and increased customer satisfaction scores over the previous year. Through their energy : dedication, our employees set an example of community service and leadership for others to follow.

We are committed to continuing our conservative financial policies and maximizing the opportunities arising from the inherent strength in our core business. In sum, our financial base is strong, our operational structure is stable and our corpc effort to be a good citizen in the communities we serve continues to gain strength and recognition. We will uphold our commitment and responsibility to seek to enhance the value of your investment and provide our customers with the best possible service in whatever environment we face in the coming years.

Thank you for the confidence and support you have given us.

Gary R. Hedrick
President and Chief Executive Officer

George W. Edwards, Jr.
Chairman of the Board

Operating Statistics (2003-1999) (1998-1994)

	2003	2002	2001	2000	
Electric Utility Operating Revenues (in thousands):					
Retail:					
Residential	$ 171,459	$ 166,320	$ 159,263	$ 157,341	$
Commercial and Industrial, Small	165,434	163,553	161,997	158,652	
Commercial and Industrial, Large	43,294	43,419	43,644	44,105	
Sales to Public Authorities	73,136	70,802	70,372	70,548	
Total Retail	453,323	444,094	435,276	430,646	
Wholesale:					
Sales for Resale	3,223	32,228	52,879	45,698	
Total Wholesale	456,546	476,322	488,155	476,344	
Fuel Revenues Sales	122,761	158,650	164,335	124,126	
Economy Sales Sales	76,536	43,654	92,452	84,918	
Other Sales	8,519	11,459	24,763	16,261	
Total Operating Revenues	$ 664,362	$ 690,085	$ 769,705	$ 701,649	$
Number of Customers (end of year):					
Residential	289,179	281,874	276,200	271,588	
Commercial and Industrial, Small	30,254	29,281	28,573	27,947	
Commercial and Industrial, Large	145	141	140	133	
Other	4,524	4,431	4,308	4,054	
Total Customers	324,102	315,727	309,221	303,722	
Energy Supplied, MWh:					
Generated	7,740,923	7,785,938	8,183,713	8,706,790	
Purchased and Interchanged	1,250,707	1,549,875	951,359	905,770	
Total Energy Supplied	8,991,630	9,335,813	9,135,072	9,612,560	
Energy Sales, MWh:					
Retail:					
Residential	1,932,171	1,870,931	1,789,199	1,767,928	
Commercial and Industrial, Small	2,096,860	2,078,758	2,069,517	2,026,768	
Commercial and Industrial, Large	1,197,065	1,161,815	1,174,235	1,142,183	
Sales to Public Authorities	1,224,349	1,212,180	1,185,521	1,177,883	
Total Retail	6,450,445	6,321,684	6,218,472	6,114,742	

Wholesale:					
Sales for Resale	67,754	986,134	1,460,383	1,282,540	
Economy Sales	1,920,882	1,483,465	929,914	1,714,288	
Total Wholesale Sales	1,988,636	2,469,599	2,390,297	2,996,828	
Total Energy Sales	8,439,081	8,791,283	8,608,769	9,111,570	
Losses and Company Use	552,549	544,530	526,303	500,990	
Total Net	8,991,630	9,335,831	9,135,072	9,612,560	
Native System:					
Peak Load, MW	1,308	1,282	1,199	1,159	
Net Generating Capacity for Peak, MW	1,500	1,500	1,500	1,500	
Total System:					
Peak Load, MW	1,546	1,509	1,485	1,427	
Net Generating Capacity for Peak, MW	1,500	1,500	1,500	1,500	
System Capacity Factor	60.1%	61.1%	60.6%	66.0%	

(a) Financial data are based on the results for the Predecessor Company for periods prior to February 11, 1996 and the Reorganized Company there

2003 Operational Highlights

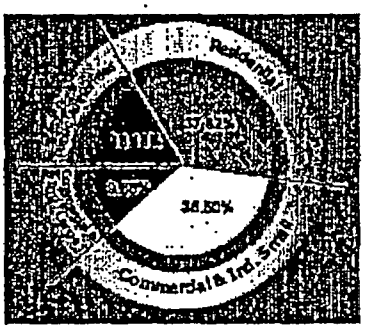
Operational	2001	2002	2003
Retail GWh Sold	6,218	6,322	6,450
% Change	1.68%	1.67%	2.02%
Native Peak (MW)	1,199	1,282	1,308
Customers at Year-End	309,221	315,727	324,102
% Change	1.81%	2.10%	2.65%
Employees at Year-End (including temporaries)	1,033	1,021	999

Generating Capacity

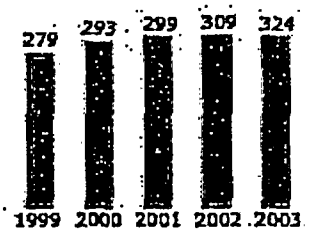
Plant	*Entitlement*	*Fuel Source*	*Energy Mix*
Palo Verde	600 MW	Nuclear	50%
Newman	482 MW	Natural Gas	
Rio Grande	246 MW	Natural Gas	27%
Copper	68 MW	Natural Gas	
Four Corners	104 MW	Coal	9%
		Purchased Power	14%
TOTAL	**1,500 MW**		**100%**

A pilot wind project began operating in April 2001 with a capacity of 1.32 MW.

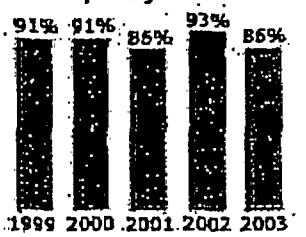
2003 Retail Base Operating Revenues



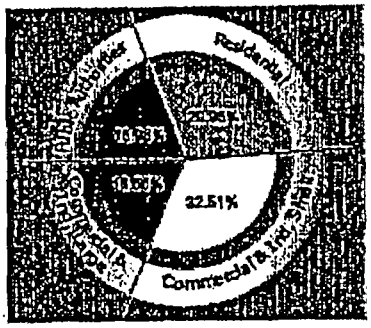
Customers Served Per Employee

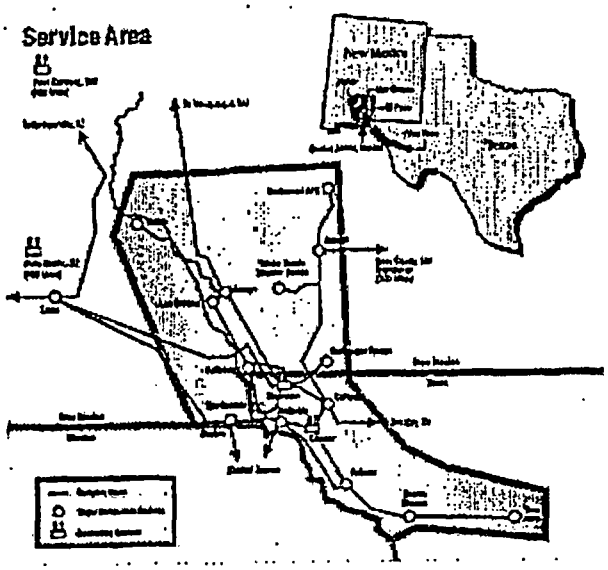


Palo Verde Capacity Factor

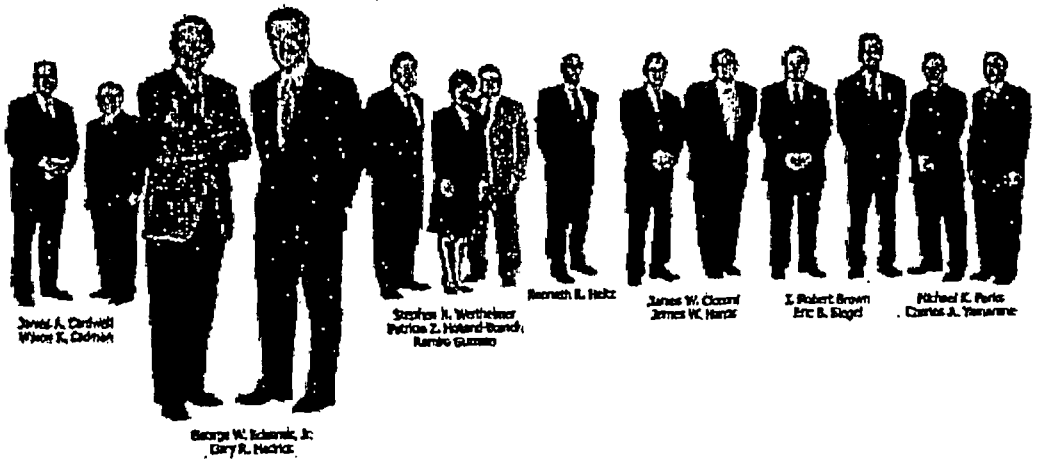


2003 Retail MWh Sales


Residential
22.51%
Commercial & Industrial


Service Area

Board of Directors



George W. Edwards, Jr.
Chairman of the Board
Retired in 1995. Prior to retirement,
President, CEO and Director of,
Kansas City Southern Railway Company,
Kansas City, MO

J. Robert Brown
President and Chairman of the Board,
Petro Stopping Centers, LP
El Paso, TX

Wilson K. Cadman
Retired in 1992. Prior to retirement,
Chairman of the Board, President and
CEO, Kansas Gas and Electric Company,
Wichita, KS and Vice Chairman of the
Board of Western Resources Inc.,
Topeka, KS

James A. Cardwell
Chairman of the Board and CEO,
Petro Stopping Centers, LP
El Paso, TX

James W. Cicconi
General Counsel and Executive Vice President,
Law and Government Affairs,
AT&T
Washington, D.C.

Ramiro Guzman
President,
Ramiro Guzman & Associates,

El Paso, TX

James W. Harris
Founder and President,
Seneca Financial Group, Inc.,
Greenwich, CT

Gary R. Hedrick
President and CEO
El Paso Electric Company
El Paso, TX

Kenneth R. Heitz
Partner,
Irell & Manella
Los Angeles, CA

Patricia Z. Holland-Branch
President, CEO and Owner,
Facilities Connection Inc.
El Paso, TX

Michael K. Parks
Managing Director
Trust Company of the West
Los Angeles, CA

Eric B. Siegel
Independent Investor and Business Consultant,
Retired Limited Partner
of Apollo Advisors, LP
Los Angeles, CA

Stephen N. Werthelmer
Managing Director
W Capital Management,
Greenwich, CT

Charles A. Yamarone
Executive Vice President,
Libra Securities, LLC
Los Angeles, CA

Officers

Gary R. Hedrick
President and Chief Executive Officer

Terry Bassham
Executive Vice President, Chief

Steven P. Busser
Treasurer

Fernando J. Gireud
Vice President, Power Marketing and International

Hector R. Puente
Vice President, Power Generation

Guillermo Silva, Jr.
Vice President, Information

Financial and Administrative Officer

J. Frank Bates
Executive Vice President, Chief Operations Officer

Raul A. Carrillo, Jr.
Senior Vice President, General Counsel and Corporate Secretary

Business

Helen Knopp
Vice President, Customer and Public Affairs

Kerry B. Lore
Controller

Robert C. McNiel
Vice President, New Mexico Affairs

Services

John A. Whitacre
Vice President, Transmission and Distribution

Scott D. Wilson
Controller

Shareholder Information

Securities and Records

The common stock of El Paso Electric is traded on the New York Stock Exchange. The ticker symbol is EE.

EPE and The Bank of New York (BONY) act as co-registrars for EPE's common stock. BONY maintains all shareholder records of EPE.

Shareholder Services

Shareholders may obtain information relating to their share position, transfer requirements, lost certificates, and other related matters by contacting BONY Shareholder Services at (800) 524-4458. This service is available to all shareholders Monday through Friday, 8 a.m. to 8 p.m., ET.

Address Shareholder Inquiries to:
The Bank of New York
Shareholder Relations
Church Street Station
P.O. Box 11258
New York, NY 10286-1258
Website: http://www.stockbny.com

Send Certificates for Transfer and Address Changes to:
The Bank of New York
Receive and Deliver Dept.
Church Street Station
P.O. Box 11002
New York, NY 10286-1002

Form 10-K Report and Shareholder Inquiries

A complete copy of EPE's Annual Report and Form 10-K for the year ended December 31, 2002, which has been filed with the Securities and Exchange Commission, including financial statements and financial statement schedules, is available without charge upon written request to:
Investor Relations
El Paso Electric
P.O. Box 982
El Paso, TX 79960
Or call: (800) 592-1634
E-mail: investor_relations@epelectric.com
Website: http://www.epelectric.com

Annual Meeting of Shareholders

The annual meeting of El Paso Electric's shareholders will be held at 10 a.m., Mountain Daylight Time on Wednesday, May 5, 2004 at the Stanton Tower Building, 100 N. Stanton, El Paso, TX 79901. In connection with the meeting, proxies will be solicited by the Board of Directors of EPE. A notice of meeting, together with a proxy statement, a form of proxy, and the Annual Report to Shareholders for 2003, were mailed on or about March 31, 2004 to shareholders of record as of March 10, 2004.

Energy Services
Department of Water and Power
City of Los Angeles

Report and Financial Statements and
Required Supplementary Information

June 30, 2003

Los Angeles Department of Water and Power
Energy Services
Financial Statements and Required Supplementary Information – June 30, 2003
Table of Contents

Los Angeles Department of Water and Power
Energy Services

Management's Discussion and Analysis
(Unaudited)

June 30, 2003

The following discussion and analysis of the financial performance of the City of Los Angeles' (the City) Department of Water and Power's (the Department), Power System Fund (Energy Services), provides an overview of the financial activities for the fiscal year ended June 30, 2003. Descriptions and other details pertaining to Energy Services are included in the notes to the financial statements. This discussion and analysis should be read in conjunction with the Energy Services' financial statements, which begin on page 18.

Background and Creation of the Department

The Department is the largest municipal utility in the United States and is a separate proprietary agency of the City, controlling its own funds with full responsibility for meeting the electric and water requirements of its service area. The Department provides electric and water service almost entirely within the boundaries of the City, which encompasses some 465 square miles, to a population of approximately 3.9 million people. Certain factors, which affect the electric industry, generally apply to the Department's operation of Energy Services.

The Department was established under the City Charter adopted in January 1925 as amended effective July 2000. It had its beginning, however, in the early 1900's. The first Board of Water and Power Commissioners was established in 1902. The responsibilities for the provision of water as well as electricity were given to a new Los Angeles Department of Public Service organized in 1911. The Department of Public Service was superceded in 1925 when a new Charter was adopted creating the Department. Subsequently the Water Works and Electric Works came to be known as the Water System (Water Services) and the Power System (Energy Services). The operations and finances of Energy Services are separate from those of Water Services.

Charter Provisions

Governance

Pursuant to the Charter of the City (the Charter), the five-member Board of Water and Power Commissioners (the Board) is the governing body of the Department and the General Manager administers the affairs and operations of the Department. The Board is granted the possession, management and control of Energy Services.

The provisions of the Charter relating to the Department are found in Article VI. Among other things, Article VI provides that all Energy Services revenue collected by the Department shall be deposited in the Power Revenue Fund, that the Board shall control the money in the Power Revenue Fund, and makes provisions for the issuance of Department bonds, notes and other evidences of indebtedness payable out of the Power Revenue Fund.

Section 245 of the Charter provides that actions of the Board shall become final at the expiration of the next five meeting days of the City Council (the Council), during which time the Council may bring the matter for review, or veto such action. If the Council votes to bring the matter for review, it has 21 days to conduct its review, otherwise the Board's action on the matter is final.

Rates

Pursuant to the Charter, the Board, subject to the approval of the Council by ordinance, fixes the rates for electric service provided by Energy Services. The Charter provides that such rates shall be fixed by the Board from time to time as necessary. The Charter also provides that such rates shall, except as authorized by the Charter, be of uniform operation for customers of similar circumstances throughout the City, as near as may be, and shall be fair and reasonable, taking into consideration, among other things, the nature of the uses, the quantity supplied, and the value of the service, and the financial impact on Energy Services resulting from such service.

A rate freeze for all Department electric customers was instituted effective April 1, 1998, which froze electric rates at the level in effect as of October 1997. This rate freeze remained in effect during fiscal year 2003.

Transfers to the Reserve Fund of the City of Los Angeles

Under the provisions of the City Charter, Energy Services transfers funds at its discretion to the reserve fund of the City. Pursuant to covenants contained in the bond indentures, the transfers may not be in excess of the increase in fund net assets before transfers to the reserve fund of the City, of the prior fiscal year. Such payments are not in lieu of taxes and are recorded as a reduction of fund net assets in accordance with governmental accounting standards. Energy Services made a transfer of 7% of its fiscal 2002 operating revenues, plus an additional $29 million transfer, totaling $185 million to the reserve fund of the City in fiscal 2003. Energy Services expects to transfer 7% of its fiscal 2003 operating revenues, or approximately $150 million, to the reserve fund of the City in fiscal 2004.

Competitive Abilities

In 1996, certain amendments to the Charter were approved to enable the Department to compete more effectively in a deregulated electric market. These amendments are part of the amended Charter and include:

- Greater flexibility in debt structuring;
- The express authority to sell energy and related products and services outside the City;
- The ability to enter into contracts with retail customers for terms of up to ten years;
- The ability to invest moneys in the Power Revenue Fund in any investment authorized for City funds; and
- The authority to finance the energy efficiency investments of the Department's retail customers.

Critical Accounting Policies

Method of Accounting

The accounting records of Energy Services are maintained in accordance with accounting principles generally accepted in the United States of America. As a government-owned utility, in prior years the Department applied all statements issued by the Governmental Accounting Standards Board (GASB) and all statements and interpretations issued by the Financial Accounting Standards Board (FASB), which are not in conflict with statements issued by the GASB. In fiscal year 2003, the Department changed its election under the guidance in GASB Statement No. 20, "*Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities that Use Proprietary Fund Accounting*" (GASBS 20), to follow GASB statements and only FASB statements and interpretations issued on or before November 30, 1989. The Department is required to retroactively apply this change by restating prior years presented. The impact on Energy Services' financial statements as a result of this change was the discontinuation of the application of Financial Accounting Standard No. 133, "*Accounting for Derivative Instruments and Hedging Activities*" (SFAS No. 133). The Department adopted SFAS No. 133 in fiscal year 2001 and consequently began reporting its derivative instruments at fair value. With the change in election under GASBS 20, Energy Services is no longer required to report its derivative instruments at fair value. Energy Services restated its prior year financial statements to retroactively apply this change in election. See Note 2 to the financial statements for further information and a description of the impact of the change on prior period results.

Energy Services' rates are determined by the Board and are subject to review and approval by the Council. As a regulated enterprise, the Department's financial statements are prepared in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, *"Accounting for the Effects of Certain Types of Regulation,"* which requires that the effects of the ratemaking process be recorded in the financial statements. Such effects primarily concern the time at which various items enter into the determination of changes in fund net assets in order to follow the principle of matching costs and revenues. The primary impact of SFAS No. 71 is a deferral of a portion of revenues authorized for debt reduction. The Department deferred $70 million and $69 million in fiscal years 2003 and 2002, respectively. The deferrals relate to a rate established to put aside funds for debt reduction. Funds collected are held in trust and may be used to reduce future purchase power obligations at the discretion of the Board.

California Receivables

The Department's policy is to reserve for known contingencies that are probable and can be estimated. The Department has recorded receivables due from two California agencies totaling $169 million as of June 30, 2003. Energy Services has also recorded a $40 million reserve against this receivable, representing management's estimate of the most probable potential refunds. It is management's belief that the entire receivable represents a valid claim and should be paid with interest by the parties owing the Department, primarily the California Power Exchange (the CPX) and the California Independent Systems Operator. In January 2001, the CPX filed for bankruptcy and management has not yet determined how and when receivables will be paid from that organization. Two utilities with significant amounts due to these agencies, Southern California Edison Company and Pacific Gas & Electric, have previously stated in public disclosure documents that they may not be able to pay for all the power they consumed in 2001. Southern California Edison Company has paid all amounts due by it to the CPX, however the amounts remain in an escrow account pending the resolution of disbursement of the funds. Pacific Gas & Electric has filed for protection under Chapter 11 of the Federal Bankruptcy Statute and amounts due from that entity are outstanding.

Investment Policy and Controls

The Department's cash, other than cash in certain trust funds, is deposited with the City Treasurer, who invests the funds in securities under the City Treasurer's pooled investment program, for the purpose of maximizing interest earnings. Under the program, available funds of the City and its independent operating departments are invested on a combined basis. The primary responsibilities of the City Treasurer are to protect the principal and asset holdings of the City's portfolio and to ensure adequate liquidity to provide for the prompt and efficient handling of City disbursements. The City Treasurer invests these funds in compliance with the applicable California Government Code and the City's Investment Policy. Generally, investments are limited to government securities with credit ratings of AAA and are of varying maturities which can range from less than 90 days to in excess of two years.

Debt Management Program

The debt restructuring element of the Debt Management Program includes the issuance of refunding bonds to achieve debt service savings and to accelerate the maturity of certain bonds while maintaining an appropriate overall annual debt service schedule for all of the Department's obligations in connection with Energy Services. As of June 30, 2003 the Department had completed the major portion of its refunding program, including the issuance of several series of refunding bonds payable from the Power Revenue Fund under a Master Bond Resolution adopted by the Board on February 6, 2001. Pursuant to this refunding program, the Department issued $2.1 billion principal amount of refunding bonds to redeem, defease or purchase $1.5 billion principal amount of Department revenue bonds payable from the Power Revenue Fund and $0.6 billion principal amount of Intermountain Power Authority (IPA) bonds. As of August 2003, Energy Services had completed its refunding program.

In addition, Energy Services has $836 million on deposit in trust funds restricted for the use of debt reduction as of June 30, 2003. The Debt Management Program is intended to bring Energy Services' cost structure to a competitive level.

Using This Financial Report

This financial annual report consists of the financial statements and reflects the self-supporting activities of Energy Services that are funded primarily through the sale of energy, transmission and distribution services to the public it serves.

Balance Sheets, Statements of Revenue, Expenses and Changes in Fund Net Assets, and Statements of Cash Flows

The financial statements provide an indication of Energy Services' financial health. The Balance Sheets include all of Energy Services' assets and liabilities, using the accrual basis of accounting, as well as an indication about which assets can be utilized for general purposes, and which assets are restricted as a result of bond covenants and other commitments. The Statements of Revenue, Expenses, and Changes in Fund Net Assets report all of the revenues and expenses during the time periods indicated. The Statements of Cash Flows report the cash provided and used by operating activities, as well as other cash sources such as investment income and cash payments for bond principal and capital additions and betterments.

The following table summarizes the financial condition and changes to fund net assets of Energy Services as of and for the fiscal years ending June 30, 2003 and 2002 (amounts in millions):

Table 1 - Summary of financial condition and changes in fund net assets

	June 30,	
Assets	2003	2002*
Utility plant, net	$ 4,964	$ 4,566
Investments	1,004	1,067
Other long-term assets	1,412	1,508
Current assets	1,096	1,058
	$ 8,476	$ 8,199
Liabilities and Fund Net Assets		
Long-term debt	$ 3,232	$ 3,282
Other long-term liabilities	722	687
Current liabilities	829	605
	4,783	4,574
Fund net assets:		
Invested in capital assets, net of related debt	1,569	1,183
Restricted	1,188	1,048
Unrestricted	936	1,394
Total fund net assets	3,693	3,625
	$ 8,476	$ 8,199
Revenue, Expenses, and Changes in Fund Net Assets		
Operating revenues	$ 2,146	$ 2,235
Operating expenses	(1,916)	(1,871)
Operating income	230	364
Investment income	132	130
Other income and expenses, net	30	91
Debt expenses	(139)	(153)
Transfer to the reserve fund of the City of Los Angeles	(185)	(179)
Increase in fund net assets	68	253
Beginning balance of fund net assets	3,625	3,372
Ending balance of fund net assets	$ 3,693	$ 3,625

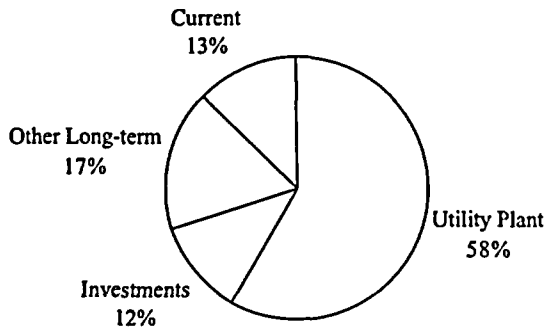
** As restated, for the change in election under GASBS 20.*
See Note 2 of financial statements.

Assets

Utility Plant

Utility plant is the first category of assets shown on the balance sheet. The utility industry is unique in this regard as most other industries list their long-term assets such as plant and equipment after current assets on the balance sheet. This difference is due to the capital-intensive nature of the utility industry with the most significant portion of that capital being invested in utility plant. As depicted in the chart below, utility plant, net of accumulated depreciation, makes up 58% of the total assets of Energy Services as of June 30, 2003.

Chart 1 - Total Assets by Type



During fiscal year 2003, Energy Services capitalized $288 million of additions to utility plant in service. Of the $288 million, $203 million, or 70% related to distribution and transmission utility plant assets. These additions were incurred for normal capital activities to maintain and support load growth of the distribution and transmission systems. Furthermore, Energy Services had capital improvements to its general office building and purchased software during the year, contributing to the increase in general plant assets.

Construction work in progress increased by $383 million over fiscal year 2002 primarily as a result of ongoing local generation projects under the Integrated Resource Plan.

Energy Services has budgeted approximately $790 million of capital expenditures for fiscal year 2004.

The Department's strategy is to have generating utility plant assets that can produce energy from a variety of fuel types. This is referred to as a hedged power supply. This is important in that if the costs related to a particular fuel type rise substantially in a short period of time, the Department can utilize its mix of generation assets to meet customer demand and to minimize increases in fuel expense. The Department has implemented a $2 billion, ten-year plan to upgrade its local power plants and to implement a program that includes demand side management, alternative energy sources and distributed generation. Through June 30, 2003, the Department has incurred $931 million related to such upgrades.

The table below summarizes the generating resources available to the Department as of June 30, 2003. These resources include those owned by the Department (either solely or jointly with other utilities) as well as resources available through long-term purchase agreements. Generating station capacity is measured in megawatts.

Table 2 - Generation resources

Resource Type	Number of Units	Maximum Capacity (MWs)		Net Dependable Capacity
Oil and gas	22	3,397	*	3,169
Coal	7	1,756		1,660
Nuclear	3	368		366
Hydro	29	1,948		1,832
	61	7,469		7,027

* Includes the capacity of all the Valley Generating Station (558 MW). Due to the long-term lay-up of Units 1 and 2 (190 MW) the capacity has been reduced to 368 MW.

Due to Water Services

As of June 30, 2003, Energy Services owed $67 million to Water Services, an increase of $61 million over June 30, 2002. Amounts owed between the two funds are generally settled within one month. The increase as of June 30, 2003 is due to a short term suspension of payments to Water Services by Energy Services of amounts owing for cash management purposes, and represents three months of amounts outstanding. The additional months outstanding were repaid to Water Services as of September 2003.

Investments

The Department sets aside funds to be used in future years for specified purposes. At June 30, 2003, a total of $1.0 billion in restricted and other investments was held by Energy Services, consisting primarily of U.S. government securities, bonds and repurchase agreements and other investments such as commercial paper and negotiable certificates of deposit. These investments are set aside for the following purposes:

- Refunding debt: the escrow investments are held to call specified revenue bonds at scheduled maturity dates.
- Debt reduction: the debt reduction trust funds were established during fiscal year 1997 to provide for the payment of principal and interest on long-term debt obligations and purchased power obligations arising from the Department's participation in the Intermountain Power Project (IPA) and the Southern California Public Power Authority (SCPPA).
- Nuclear decommissioning: nuclear decommissioning trust funds will be used to pay the Department's share of decommissioning the Palo Verde Nuclear Generating Station at the end of its useful life.
- Post retirement benefits: the postretirement health care benefit trust fund was established to provide for the payment of the Department's postretirement health care benefits.
- Other: other investments consist of funds held by SCPPA on behalf of the Department and by the Department for payment of future SCPPA obligations. Certain of these investments are currently being used by the Department to provide for the payment of principal and interest on long-term debt obligations and purchased power obligations arising from the Department's participation in SCPPA. The Department has utilized most of its internal funds through June 30, 2003 to pay for purchased power costs.

The Department has a securities lending program which allows it to lend up to 20% of its investments held in the debt reduction trust funds, decommissioning trust funds, and plan assets held in the postretirement benefits trust fund for securities, cash collateral or letters of credit equal to 102% of the market value of the loaned securities and interest, if any. The lending agent provides indemnification for borrower default. There were no violations of legal or contractual provisions and no borrower or lending agent default losses during fiscal years 2003 and 2002.

In addition, Energy Services participates in the City's securities lending program and is allocated its share of the collateral received and the related liability, as well as earnings from the program. As of June 30, 2003 and 2002, the amount of collateral and liability pertaining to securities lending programs were $243 million and $187 million, respectively.

Management believes that participation in these securities lending programs results in no credit risk exposure to the Department because the amounts owed to the borrowers exceed the amounts the borrowers owe to the Pool and the Department

Other Long-term Assets

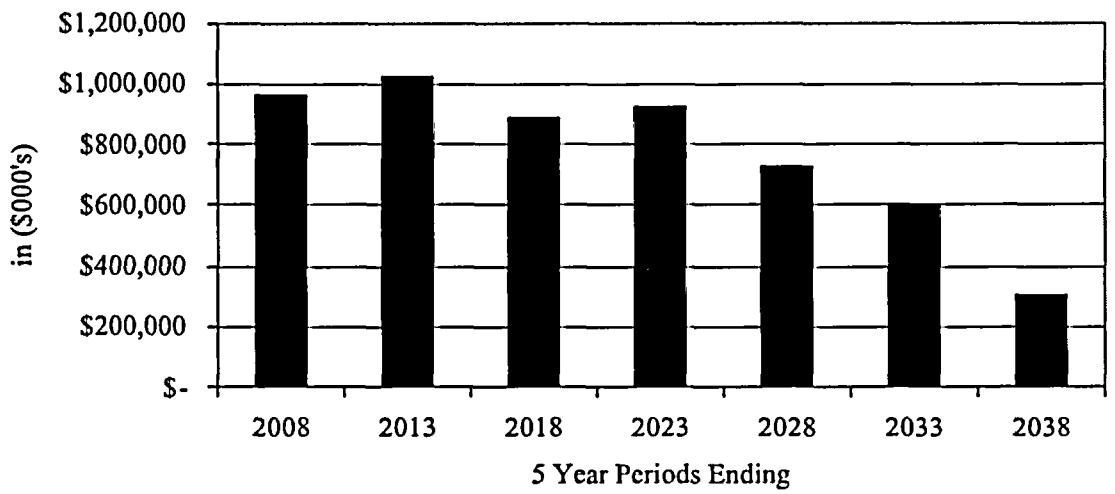
A significant portion of other long-term assets is Energy Services' long-term notes receivable. Prior to fiscal year 2002, the Department transferred $1.3 billion to IPA in exchange for long-term notes receivable. The funds transferred were obtained from the debt reduction trust fund and through the issuance of variable rate bonds. IPA used the proceeds to defease bonds with a face value of $1.4 billion. The Department's payments to IPA, which are included in operating expenses in Table 1, will be partially offset by interest payments and principal maturities from the long-term notes receivable.

Liabilities and Fund Net Assets

Long-term debt

As of June 30, 2003, Energy Services' total long-term debt balance was $3.4 billion. During fiscal year 2003, Energy Services paid off its $389 million in revenue certificates by issuing an equivalent amount of variable rate debt. Furthermore, the Department issued an additional $14 million in Mini-Bonds to employees and retirees and paid $31 million in bond maturities. Outstanding principal, plus scheduled interest as of June 30, 2003, is scheduled to mature as shown in the chart below:

Chart 2: Debt Service Requirements



As of June 30, 2003, $730 million principal amount of long-term debt is considered defeased and remains outstanding. This debt, together with trust funds set aside for its full repayment at scheduled maturity dates, has been derecognized and is not reflected on the balance sheet.

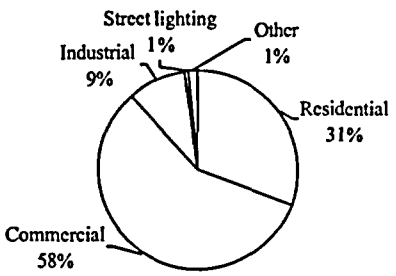
In July 2003, Standard & Poors and Fitch affirmed Energy Services' bond rating of AA- due to Energy Services' strong financial position, debt reduction program, hedged power supply, experienced management team, and favorable customer/revenue mix.

Changes in Fund Net Assets

Revenues

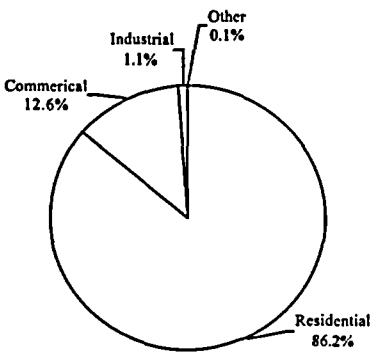
The operating revenues of Energy Services are generated from wholesale and retail customers. There are four major customer categories of retail revenue. These categories include residential, commercial, industrial, and other, which includes public street lighting. Chart 3 summarizes the percentage contribution of retail revenues from each customer segment in fiscal year 2003.

Chart 3: Revenues



While commercial customers consume the most electricity, residential customers represent the largest customer class. As of June 30, 2003, Energy Services had approximately 1.4 million customers. As shown in Chart 4, 1.2 million, or 86% of total customers were in the residential customer class as of June 30, 2003.

Chart 4: Number of Customers



Fiscal year 2003

While retail revenues increased from fiscal year 2002, overall operating revenues decreased from fiscal year 2002 levels due to a reduction in wholesale business. Wholesale prices declined from an average of $68 per MWH in fiscal year 2002 to an average of $44 per MWH in fiscal year 2003 for the Department. The decline in market pricing resulted in a reduction of market opportunities for the Department's excess generation.

Fiscal year 2002

Operating revenues decreased from fiscal year 2001 levels due to the stabilization of the California energy market, the impact of the energy efficiency and conservation programs put in place, and weather conditions. Wholesale business was the primary element of change. Energy markets stabilized in the early summer period of fiscal year 2001 due to a substantial decline in natural gas prices, the impact of FERC price caps and the effects of conservation on demand. As a result, wholesale prices dropped substantially and revenues were impacted by a decrease in wholesale volumes sold, from 3.7 million MWH in fiscal year 2001 to 1.5 million MWH in fiscal year 2002, and a decline in the average price for energy from $228 per MWH in fiscal 2001 to $68 per MWH in fiscal year 2002. Retail volumes and sales also declined primarily due to the decline in the general economy which also had a negative impact on commercial and industrial sales.

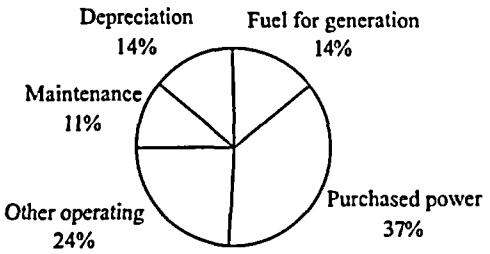
Operating Expenses

Fuel for generation expense and purchased power expense are two of the largest expenses that Energy Services incurs each fiscal year. Fuel for generation expense includes the cost of fuel that is used to generate energy. The majority of fuel costs include the cost of natural gas, coal, and nuclear fuel.

Purchased power expense includes the cost of buying power on the open market and paying the current portion of Energy Services' purchase power contracts. Under these purchase power contracts, the Department has an entitlement to the energy that is produced at various generating stations, and an entitlement to the use of various transmission facilities. Most of these contracts require the Department to pay for these services regardless of whether the energy or transmission is used. These types of contracts are referred to as "take-or-pay" contracts.

Depreciation expense is computed using the straight-line method based on service lives for all projects completed after July 1, 1973, and for all office and shop structures, related furniture and equipment, and transportation and construction equipment. Depreciation for facilities completed prior to July 1, 1973 is computed using the 5% sinking fund method based on estimated service lives. The Department uses the composite method of depreciation and therefore groups assets into composite groups for purposes of calculating depreciation expense. Estimated service lives range from 5 to 75 years. Amortization expense for computer software is computed using the straight-line method over 5 years. The chart below summarizes Energy Services' operating expenses during fiscal year 2003:

Chart 5: Operating Expenses



Fiscal year 2003

Fiscal year 2003 operating expenses were $45 million higher as compared to the prior year. Maintenance and other operating expenses had the largest increase of $77 million due to increased labor and employee benefit costs, in addition to continued increases in security costs. The largest increases incurred by Energy Services were in distribution plant maintenance, production operating expense and customer accounting expenses.

Depreciation expense decreased during fiscal year 2003 as compared to fiscal year 2002, mainly due to a change in estimate of service lives of certain utility plant assets and the cessation of depreciation of two major facilities as they reached the end of their useful lives for accounting purposes. This change in estimate resulted in a reduction to Energy Services' depreciation expense by a total of $54 million. The decrease was offset by additional depreciation in the current year as a result of additions to utility plant.

Fiscal year 2002

Fiscal year 2002 operating expenses were $725 million lower as compared to the prior year. This reduction was mostly due to a reduction in generation expenses and purchased power that corresponds with the decline in sales of surplus energy and transmission and generation capacity. In addition, the cost of natural gas to serve retail customers declined substantially during 2002 and further reduced the cost of generation.

Non-Operating Revenue and Expenses

Fiscal year 2003

The major non-operating activities of Energy Services for fiscal year 2003 included the transfer of $185 million to the City's General Fund; interest income earned on investments of $132 million; and $139 million in debt expenses. Furthermore, Energy Services recognized an $8 million impairment charge during fiscal year 2003 relating to the sale of one of its administrative facilities. The Department further reduced the sales price of the facilities as a result of mold that was discovered in the facility. See Note 14 of the financial statements for further discussion.

Interest on investments followed the general trend in interest rates and declined from an average yield of 344% in fiscal year 2002 to 2.27% in fiscal year 2003. Interest on debt declined due to lower rates on variable rate debt and the effects of the debt restructuring program which lowered average interest rates on fixed rate debt.

Fiscal year 2002

The major non-operating activities of Energy Services for fiscal year 2002 included a $68 million gain on the sale of 50% of its 20% interest in the Mohave Generating Station; the transfer of $179 million to the City's General Fund; interest income earned on investments of $130 million; and $153 million in debt expenses.

Interest on investments followed the general trend in interest rates and declined from an average yield of 5.30% in fiscal year 2001 to 3.44% in fiscal year 2002. Interest on debt declined due to lower rates on variable rate debt and the effects of the debt restructuring program which lowered average interest rates on fixed rate debt.

Risk Factors

Energy Services' primary business is to provide its retail customers with reliable electricity service. Energy Services manages its overall cost of providing service by monitoring wholesale markets and purchasing electricity for customers when the market price is below the marginal cost of producing energy from Department resources. Energy Services sells its surplus generation to the market when the cost of excess resources is below the market price. The transactions are executed with external parties, primarily other utility companies and broker dealers which we refer to as counterparties.

The Department manages its counterparty risk by evaluating each of the entities that it transacts with and limiting its transaction volume based on an assessment of the entity's financial strength. In addition, the Department enters into master netting agreements with other Western System Coordinating Council participants.

Energy Services is subject to market risk in that the wholesale market price of energy impacts its cost of energy purchases in addition to its ability to market surplus power. The Department manages that risk by devoting its owned and contract resources to service retail customers. Only surplus resources are made available to wholesale markets. During fiscal 2003, the Department's peak load was 5,185 MWs. Net dependable capability from owned and contract resources totaled 7,027 MWs.

PRICEWATERHOUSECOOPERS

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Report of Independent Auditors

To the Board of Water and Power Commissioners
Department of Water and Power
City of Los Angeles

In our opinion, the accompanying balance sheets and the related statements of revenue, expenses and changes in fund net assets and of cash flows present fairly, in all material respects, the financial position of the Power System (Energy Services) of the Department of Water and Power of the City of Los Angeles at June 30, 2003 and 2002, and the changes in its fund net assets and its cash flows for each of the three years in the period ended June 30, 2003 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Department's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 2 to the financial statements, effective July 1, 2002, Energy Services changed its election under Governmental Accounting Standards Board Statement No. 20, "*Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities that Use Proprietary Fund Accounting,*" and no longer applies Financial Accounting Standards Board statements and interpretations issued after November 30, 1989. Energy Services has restated all prior years presented to give effect of this change in election.

The management's discussion and analysis included on pages 1 through 16 is not a required part of the basic financial statements but is supplementary information required by the Governmental Accounting Standards Board. We have applied certain limited procedures, which consisted primarily of inquiries of management regarding the methods of measurement and presentation of the required supplementary information. However, we did not audit the information and express no opinion on it.

PricewaterhouseCoopers LLP

November 26, 2003, except for Note 16, which is as of December 17, 2003

Los Angeles Department of Water and Power
Energy Services Balance Sheets, as restated
(Amounts in thousands)

	June 30,	
	2003	2002
Assets		
Non-Current Assets		
Utility Plant		
Generation	$ 2,622,137	$ 2,614,229
Transmission	829,457	809,337
Distribution	3,893,836	3,716,333
General	915,054	857,244
	8,260,484	7,997,143
Accumulated depreciation	4,073,466	3,828,328
	4,187,018	4,168,815
Construction work in progress	763,000	379,970
Nuclear fuel, at amortized cost	13,431	16,943
	4,963,449	4,565,728
Restricted and other investments	1,004,372	1,066,982
Long-term California wholesale energy receivable, net	128,715	163,354
Long-term notes receivable	1,164,457	1,219,635
Net pension asset	119,198	125,655
	1,412,370	1,508,644
Current Assets		
Cash and cash equivalents - unrestricted	126,072	166,760
Cash and cash equivalents - restricted	120,742	83,463
Cash collateral received from securities lending transactions	243,361	187,180
Customer and other accounts receivable, net of $11,000 allowance for losses	216,535	242,778
Current portion of long-term notes receivable	63,827	70,323
Accrued unbilled revenue	118,853	120,028
Materials and fuel	111,236	107,590
Prepayments and other current assets	95,635	80,002
	1,096,261	1,058,124
	$ 8,476,452	$ 8,199,478

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

Los Angeles Department of Water and Power
Energy Services Balance Sheets, as restated
(Amounts in thousands)

	June 30,	
	2003	2002
Fund Net Assets and Liabilities		
Fund Net Assets		
Invested in capital assets, net of related debt	$ 1,568,405	$ 1,182,960
Restricted fund net assets	1,188,192	1,048,442
Unrestricted fund net deficit	936,465	1,393,941
	3,693,062	3,625,343
Long term debt	3,232,088	3,281,858
Other Non-Current Liabilities		
Deferred credits	466,167	421,832
Accrued postretirement liability	230,693	244,190
Accrued workers' compensation claims	25,163	21,300
Commitments and contingencies (Notes 6 and 15)	-	-
	722,023	687,322
Current Liabilities		
Current portion of long-term debt	163,180	131,730
Accounts payable and accrued expenses	212,161	148,722
Payable to the reserve fund of the City of Los Angeles	29,000	25,000
Accrued interest	49,723	55,504
Accrued employee expenses	64,407	50,795
Due to Water Services	67,447	6,024
Obligation under securities lending transactions	243,361	187,180
	829,279	604,955
	$ 8,476,452	$ 8,199,478

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

Los Angeles Department of Water and Power
Energy Services Statements of Revenue, Expenses, and Changes in Fund Net Assets, as restated
(Amounts in thousands)

	Year Ended June 30,		
	2003	2002	2001
Operating Revenues			
Residential	$ 643,641	$ 632,113	$ 655,847
Commercial and industrial	1,403,422	1,377,135	1,423,730
Sales for resale	64,097	191,073	943,844
Other	47,544	46,316	47,301
Uncollectible accounts	(12,791)	(11,573)	(11,872)
	2,145,913	2,235,064	3,058,850
Operating Expenses			
Fuel for generation	273,905	280,851	876,187
Purchased power	697,824	688,790	893,864
Maintenance and other operating expenses	675,181	598,391	545,374
Depreciation and amortization	268,612	302,887	280,010
	1,915,522	1,870,919	2,595,435
Operating Income	230,391	364,145	463,415
Other Income and Expense			
Investment income	132,431	130,079	180,553
Gain on sale of utility plant asset	-	67,615	-
Other non-operating income	17,013	20,934	6,081
	149,444	218,628	186,634
Other non-operating expenses	4,807	19,724	5,388
	144,637	198,904	181,246
Loss on asset impairment and abandoned projects	(8,330)	-	(43,519)
	136,307	198,904	137,727
Debt Expenses			
Interest on debt	141,238	154,600	185,378
Allowance for funds used during construction	(1,799)	(1,393)	(1,123)
	139,439	153,207	184,255
Contributions in aid of construction	25,818	22,014	16,730
Change in fund net assets before transfers to the reserve fund of the City of Los Angeles	253,077	431,856	433,617
Transfers to the reserve fund of the City of Los Angeles	185,358	179,153	119,800
Increase in fund net assets	67,719	252,703	313,817
Fund net assets			
Beginning of period	3,625,343	3,372,640	3,058,823
End of period	$ 3,693,062	$ 3,625,343	$ 3,372,640

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

Los Angeles Department of Water and Power
Energy Services Statements of Cash Flows, as restated
(Amounts in thousands)

	Year Ended June 30,		
	2003	2002	2001
Cash Flows from Operating Activities:			
Cash Receipts			
Cash receipts from retail customers	$ 2,195,695	$ 2,088,916	$ 2,187,850
Cash receipts from retail customers for other agency services	269,158	273,361	305,018
Cash receipts from wholesale customers	112,613	266,489	747,601
Cash receipts from interfund services provided	283,803	256,774	259,453
Other operating cash receipts	-	-	4,690
Cash Disbursements			
Cash payments to employees	(368,289)	(328,508)	(316,013)
Cash payments to suppliers	(1,133,505)	(1,241,118)	(1,948,551)
Cash payments for interfund services used	(287,448)	(254,213)	(249,747)
Cash payments to other agencies for fees collected	(271,246)	(276,419)	(284,116)
Other operating cash payments	(8,196)	(349)	-
	792,585	784,933	706,185
Cash Flows from Noncapital Financing Activities:			
Payments to the reserve fund of the City of Los Angeles	(181,358)	(154,153)	(119,800)
Cash received for state grant	-	8,000	8,000
Cash disbursed for state grant expenses	-	(14,753)	(1,247)
Interest paid on noncapital revenue bonds	(6,862)	(9,829)	(18,132)
	(188,220)	(170,735)	(131,179)
Cash Flows from Capital and Related Financing Activities:			
Additions to plant and equipment, net	(672,865)	(523,445)	(453,380)
Proceeds from sale of utility plant asset	-	95,000	-
Contributions in aid of construction	26,025	11,060	11,364
Purchases of escrow investments	(34,408)	-	(176,843)
Proceeds from escrow investment maturities	28,593	250,315	528,770
Principal payments and maturities on long-term debt, net	(419,320)	(392,699)	(1,672,236)
Issuance of bonds and revenue certificates, net	402,385	112,837	1,275,939
Debt interest payments	(143,462)	(136,517)	(193,189)
	(813,052)	(583,449)	(679,575)
Cash Flows from Investing Activities:			
Purchases of investment securities	(4,637,343)	(3,197,807)	(3,177,653)
Proceeds from sales and maturities of investment securities	4,636,609	2,857,321	3,261,389
Purchase of long-term notes receivable, net	-	-	(186,435)
Maturities of long-term notes receivables	70,322	36,002	-
Investment income	135,690	131,372	159,931
	205,278	(173,112)	57,232
Cash and Cash Equivalents:			
Net (decrease)	(3,409)	(142,363)	(47,337)
Beginning of year	250,223	392,586	439,923
End of year	$ 246,814	$ 250,223	$ 392,586

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

Los Angeles Department of Water and Power
Energy Services Statements of Cash Flows, as restated, continued
(Amounts in thousands)

	Year Ended June 30,		
	2003	2002	2001
Reconciliation of operating income to net cash provided by operating activities			
Operating income	$ 230,391	$ 364,145	$ 463,415
Adjustments to reconcile operating income to net cash provided by operating activities			
Depreciation and amortization	268,612	302,887	280,010
Provision for losses on customer and other accounts receivable	12,791	11,573	11,872
Changes in assets and liabilities:			
Customer and other accounts receivable	43,697	32,373	(155,754)
Accrued unbilled revenue	1,175	4,449	6,123
Materials and fuel	(3,646)	(2,610)	(13,758)
Net pension asset	6,457	(13,393)	(12,096)
Accounts payable and accrued expenses	63,439	(35,235)	34,539
Deferred credits	44,335	70,938	71,722
Due to Water Services	61,423	(1,316)	5,996
Accrued postretirement liability	49,863	41,055	28,867
Workers' compensation liability and other	14,048	10,067	(14,751)
Cash provided by operating activities	$ 792,585	$ 784,933	$ 706,185
Non-cash capital and related financing activities:			
Loss on asset impairment and abandoned projects	$ (8,330)	$ -	$ (43,519)

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

NOTE 1: Summary of Significant Accounting Policies

The Department of Water and Power of the City of Los Angeles (the Department) exists as a separate proprietary agency of the City of Los Angeles (the City) under and by virtue of the City Charter enacted in 1925 and as revised effective July 2000. The Department's Power System (Energy Services) is responsible for the generation, transmission, and distribution of electric power for sale in the City.

Method of accounting

The accounting records of Energy Services are maintained in accordance with accounting principles generally accepted in the United States of America. As a government-owned utility, in prior years the Department applied all statements issued by the Governmental Accounting Standards Board (GASB) and all statements and interpretations issued by the Financial Accounting Standards Board (FASB), which are not in conflict with statements issued by the GASB. In fiscal year 2003 the Department changed its election under the guidance in GASB Statement No. 20, "*Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities that Use Proprietary Fund Accounting*" (GASBS No. 20), to follow all GASB statements and only FASB statements and interpretations issued on or before November 30, 1989. Prior periods were restated. See Note 2.

The Department's rates are determined by the Board of Water and Power Commissioners (the Board) and are subject to review and approval by the City Council. As a regulated enterprise, the Department utilizes Statement of Financial Accounting Standards (SFAS) No. 71, "*Accounting for the Effects of Certain Types of Regulation,*" which requires that the effects of the ratemaking process be recorded in the financial statements. Such effects primarily concern the time at which various items enter into the determination of changes in fund net assets. Accordingly, Energy Services records various regulatory assets and liabilities to reflect the Board's actions. Management believes that Energy Services meets the criteria for continued application of SFAS No. 71, but will continue to evaluate its applicability based on changes in the regulatory and competitive environment (see Note 3).

Use of estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

NOTE 1: (continued)

Utility plant

The costs of additions to utility plant and replacements of retired units of property are capitalized. Costs include labor, materials, an allowance for funds used during construction (AFUDC), and allocated indirect charges such as engineering, supervision, transportation and construction equipment, retirement plan contributions, health care costs, and certain administrative and general expenses. The costs of maintemnce, repairs and minor replacements are charged to the appropriate operations and maintenance expense accounts. The original cost of property retired, net of removal and salvage costs, is charged to accumulated depreciation.

Impairment of long-lived assets

Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be fully recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of the assets to their fair value, which is normally determined through analysis of the future undiscounted net cash flows expected to be generated by the assets. If such assets are considered to be impaired, the impairment to be recognized at that time is measured by the amount that the carrying amount of the assets exceeds the fair value of the assets.

Depreciation and amortization

Depreciation expense is computed using the straight-line method based on service lives for all projects completed after July 1, 1973, and for all office and shop structures, related furniture and equipment, and transportation and construction equipment. Depreciation for facilities completed prior to July 1, 1973 is computed using the 5% sinking fund method based on estimated service lives. The Department uses the composite method of depreciation and therefore groups assets into composite groups for purposes of calculating depreciation expense. Estimated service lives range from 5 to 75 years. Amortization expense for computer software is computed using the straight-line method over 5 years. Depreciation and amortization expense as a percentage of average depreciable utility plant in service was 3.4%, 4.0% and 3.9% for fiscal years 2003, 2002 and 2001, respectively.

During fiscal year 2003, Energy Services changed its estimate of service lives of certain utility plant assets and ceased depreciating two of its major facilities as they reached the end of their useful lives for accounting purposes. This change in estimate resulted in a reduction to Energy Services' depreciation expense by a total of $54 million.

NOTE 1: (continued)

Nuclear decommissioning

The Department owns a 5.7% direct ownership interest in the Palo Verde Nuclear Generating Station (PVNGS). In addition, through its participation in the Southern California Public Power Authority (SCPPA), the Department is party to a contract for an additional 3.95% of the output of PVNGS. Nuclear decommissioning costs associated with the Department's output entitlement are included in purchased power expense (see Note 6).

Decommissioning of PVNGS is expected to commence subsequent to the year 2024. The total cost to decommission the Department's direct ownership interest in PVNGS is estimated to be $112 million in 2001 dollars. This estimate is based on an updated site-specific study prepared by an independent consultant in 2001. Prior to December 1999, the Department contributed to external trusts established in accordance with the PVNGS participation agreement and Nuclear Regulatory Commission requirements. During fiscal year 2000, the Department suspended contributing additional amounts to the trust funds, as management believes that contributions to date, combined with reinvested earnings, will be sufficient to fully fund the Department's share of decommissioning costs. The Department will continue to reinvest its investment income. The Department reinvested $4.7 million and $6.1 million of investment income in fiscal years 2003 and 2002, respectively, and recognized an offsetting expense. Decommissioning funds, which are included in restricted investments, totaled $90.6 and $85.6 million as of June 30, 2003 and 2002 (at fair value), respectively. The Department recognizes an increase in accumulated depreciation equivalent to its contributions to and realized and unrealized investment earnings from nuclear decommissioning trust funds.

Nuclear fuel

Nuclear fuel is amortized and charged to fuel for generation on the basis of actual thermal energy produced relative to total thermal energy expected to be produced over the life of the fuel. Under the provisions of the Nuclear Waste Policy Act of 1982, the federal government assesses each utility with nuclear operations, including the Department, $1 per megawatt hour of nuclear generation. The Department includes this charge as a current year expense in fuel for generation. See Note 15 for discussion of spent nuclear fuel disposal.

NOTE 1: (continued)

Cash and cash equivalents

As provided for by the California Government Code, the Department's cash is deposited with the City Treasurer in the City's general investment pool for the purpose of maximizing interest earnings through pooled investment activities. Cash and cash equivalents in the City's general investment pool are reported at fair value and changes in unrealized gains and losses are recorded in the statements of revenue, expenses, and changes in fund net assets. Interest earned on such pooled investments is allocated to the participating funds based on each fund's average daily cash balance during the allocation period. The City Treasurer invests available funds of the City and its independent operating departments on a combined basis. The Department classifies all cash and cash equivalents that are restricted either by creditors, the Board, or by law, as restricted cash and cash equivalents on the balance sheet. The Department considers its portion of pooled investments with an original maturity of three months or less to be cash equivalents.

At June 30, 2003 and 2002 restricted cash and cash equivalents includes the following (amounts in thousands):

	June 30,	
	2003	2002
Bond redemption and interest funds	$ 86,162	$ 54,209
Construction funds	222	1,027
Self insurance fund	32,475	27,475
Other	1,883	752
	$ 120,742	$ 83,463

Materials and fuel

Materials and supplies are recorded at average cost. Fuel is recorded at lower of cost and market, on an average cost basis.

Restricted and other investments

Restricted and other investments include primarily commercial paper, United States government and governmental agency securities, and corporate bonds. Investments are reported at fair value and changes in unrealized gains and losses are recorded in the statement of revenue, expenses and changes in fund net assets. Gains and losses realized on the sale of investments are generally determined using the specific identification method. The stated fair value of investments is generally based on published market prices or quotations from major investment dealers.

NOTE 1: (continued)

Accrued employee expenses

Accrued employee expenses includes accrued payroll and an estimated liability for vacation leave, sick leave and compensatory time, which is accrued when employees earn the rights to the benefits.

Debt expenses

Debt premium, discount and issue expenses are deferred and amortized to debt expense using the effective interest method over the lives of the related debt issues. Gains and losses on refundings related to bonds redeemed by proceeds from the issuance of new bonds are amortized to debt expense using the effective interest method over the shorter of the life of the new bonds or the remaining term of the bonds refunded. Gains and losses on bond defeasances financed with cash are reported as an extraordinary gain or loss on extinguishment of debt in the statements of revenue, expenses and changes in fund net assets.

Gas and electricity option and swap agreements

Gas and electricity option and location swap agreements were previously reported at fair value on the balance sheet. With the change in election under GASBS No. 20, the Department now accounts for these contracts on a settlement basis (see Note 2). The Department does not enter into gas and option agreements for trading purposes. The Department is exposed to risk of nonperformance if the counterparties default or if the swap agreements are terminated (see Note 9).

Accrued workers' compensation claims

Liabilities for unpaid workers' compensation claims are recorded at their present value when they are probable of occurrence and the amount can be reasonably estimated. The liability is actuarially determined, based on an estimate of the present value of the claims outstanding and an amount for claim-events incurred but not reported based upon the Department's loss experience, less the amount of claims and settlements paid to date. The discount rate used to calculate this liability at its present value was 4% at June 30, 2003, which approximates the Department's long term investment yield.

NOTE 1: (continued)

Overall indicated reserves for workers' compensation claims, for both Water and Energy Services, undiscounted, have increased from $40.9 million as of June 30, 2002, to $45.5 million as of June 30, 2003. This increase is mainly attributable to increased medical inflation (particularly in the area of prescription drugs), significant increases in benefit levels implemented in California in the past few years, increased payroll levels of the Department contributing to higher indemnity losses, and increasing claim frequencies experienced by the Department in the past few years. The undiscounted reserves of $45.5 million are net of $43.2 million of cumulative payments made for claims by the Department as of June 30, 2003, for all outstanding policy years. As the claims typically take longer than 1 year to settle and close out, the entire discounted liability is shown as long term on the balance sheets as of June 30, 2003 and 2002. Energy Services' portion of the undiscounted reserves as of June 30, 2003, is $28.7 million.

Customer deposits

Customer deposits represent deposits collected from customers upon opening of new accounts. These deposits are obtained when the customer does not have a previously established credit history with the Department. Original deposits plus interest is paid to the customer once a satisfactory payment history is maintained, generally after one to three years. Interest is accrued by Water Services at the prevailing rate established by the Department, which historically has been approximately 3.5%.

Water Services is responsible for collection, maintenance and refunding of these deposits for all Department customers, including those of Energy Services. As such, Water Services' balance sheets include a deposit liability of $42.3 million and $44.5 million as of June 30, 2003 and 2002, respectively. These amounts are inclusive of amounts due to both Water Services and Energy Services customers. In the event that Water Services defaults on refunds of such deposits, Energy Services would be required to pay amounts owing to its customers.

Revenues

Energy Services' rates are established by a rate ordinance, which is approved by the City Council. Energy Services sells energy to other City departments at rates provided in the ordinance. Energy Services recognizes energy costs in the period incurred and accrues for estimated energy sold but not yet billed. The Department's current rates include amounts designated for the pre-collection of out-of-market future purchase power costs. These amounts are included in deferred credits. At the discretion of the Department, these amounts will be recognized in future periods as an offset to related purchased power expense. At June 30, 2003 and 2002, $479.7 and $409.9 million, respectively, of pre-collected purchased power costs has been deferred.

NOTE 1: (continued)

Non-operating revenues

Contributions in aid of construction and other grants received by the Department for constructing utility plant and other activities are recognized as non-operating revenues when all applicable eligibility requirements, including time requirements, are met.

Included in customer and other accounts receivable as of June 30, 2003 is $20 million of amounts received prior to June 30, 2003 from the Federal Emergency Management Authority, by the City of Los Angeles on behalf of Energy Services. This amount was deposited into the City's general fund. This amount was not transferred to the Power revenue fund until July 2003, and as such represents a receivable from the City to Energy Services as of June 30, 2003.

Allowance for funds used during construction

Allowance for funds used during construction represents the cost of borrowed funds used for the construction of utility plant. Capitalized AFUDC is included as part of the cost of utility plant and as a reduction of debt expenses. The average AFUDC rate was 4.2%, 5.4% and 5.4% for each of fiscal years 2003, 2002, and 2001 respectively.

Reclassifications

Certain financial statement items for prior years have been reclassified to conform to the current year presentation.

Recent Accounting Pronouncements

In May 2002, the GASB issued GASBS No. 39, "*Determining Whether Certain Organizations Are Component Units.*" This Statement amends GASB Statement No. 14, "*The Financial Reporting Entity,*" to provide additional guidance to determine whether certain organizations for which the primary government is not financially accountable should be reported as component units, based on the nature and significance of their relationship with the primary government. Generally, it requires reporting, as a component unit, an organization that raises and holds economic resources for the direct benefit of a governmental unit. This Statement is effective for the Department beginning in fiscal year 2004. The Department does not expect that there will be a material impact to financial statements as a result of adopting this Statement.

NOTE 1: (continued)

In November 2003, the GASB issued GASBS No. 42 "*Accounting and Financial Reporting for Impairment of Capital Assets and for Insurance Recoveries.*" This Statement establishes accounting and financial reporting standards for impairment of capital assets. A capital asset is considered impaired when its service utility has declined significantly and unexpectedly. This Statement also clarifies and establishes accounting requirements for insurance recoveries. Under the standard, impaired capital assets that will no longer be used by the government should be reported at the lower of carrying value or fair value. Impairment losses on capital assets that will continue to be used by the government should be measured using the method that best reflects the diminished service utility of the capital asset. This Statement is effective for the Department beginning in fiscal year 2005 and will not require restatement of previously reported impairment charges. The Department has not yet determined the financial statement impact of adopting the new Statement.

NOTE 2: Accounting Changes

Change in election under GASB Statement No. 20

In fiscal year 2003, the Department changed its election under the guidance in GASB Statement No. 20, "*Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities that Use Proprietary Fund Accounting*" (GASBS No. 20), to follow GASB statements and only FASB statements and interpretations issued on or before November 30, 1989. The Department is required to retroactively apply this change by restating prior years presented. Management believes that this change in election represents a change to a preferable method of accounting.

The impact on Energy Services' financial statements as a result of this change was the discontinuation of the application of Financial Accounting Standard No. 133, "*Accounting for Derivative Instruments and Hedging Activities*" (SFAS No. 133). The Department adopted SFAS No. 133 in fiscal year 2001 and consequently began reporting its derivative instruments at fair value. With the change in election under GASBS No. 20, Energy Services is no longer required to report its derivative instruments at fair value, however it must now provide certain disclosures related to derivative instruments as required by GASB Technical Bulletin No. 2003-1, "*Disclosure Requirements for Derivatives Not Reported at Fair Value on the Statement of Net Assets,*" (see Note 9).

NOTE 2: (continued)

The Department has continued to apply the provisions of SFAS No. 106, "*Employers' Accounting for Postretirement Benefits Other Than Pensions,*" and recognizes expense associated with postretirement benefits other than pensions on an accrual basis. Currently, there is no prescriptive guidance under governmental standards, however the GASB is finalizing its project on accounting for postretirement benefits other than pensions. The Department will continue to apply the provisions of SFAS No. 106 until the GASB has finalized its project, and will adopt the new GASB Standard as required in the final transition guidance. See Note 12.

Energy Services restated its prior year financial statements to retroactively apply this change in election and recorded the following amounts (amounts in thousands):

	As Previously Reported	Adjustments	As Restated
	June 30, 2002		
Balance Sheets:			
Prepayments and other current assets	$ 85,540	$ (5,538)	$ 80,002
Unrestricted fund net assets	$ 1,399,479	$ (5,538)	$ 1,393,941
Total fund net assets	$ 3,630,881	$ (5,538)	$ 3,625,343
Statements of Revenue, Expenses and Changes in Fund Net Assets	Year ended June 30, 2002		
Sales for resale	$ 189,690	$ 1,383	$ 191,073
Fuel for generation	$ 280,474	$ 377	$ 280,851
Purchased power expense	$ 683,572	$ 5,218	$ 688,790
Increase in fund net assets	$ 256,915	$ (4,212)	$ 252,703
Statements of Revenue, Expenses and Changes in Fund Net Assets	Year ended June 30, 2001		
Sales for resale	$ 998,551	$ (54,707)	$ 943,844
Purchased power expense	$ 899,082	$ (5,218)	$ 893,864
Cummulative effect of change in accounting principle	$ 48,163	$ (48,163)	$ -
Increase in fund net assets	$ 315,143	$ (1,326)	$ 313,817

NOTE 2: (continued)

GASB Statements Nos. 34, 37 and 38

On July 1, 2001, the Department adopted GASB Statement No. 34 (GASBS 34), "*Basic Financial Statements and Management's Discussion and Analysis for State and Local Governments,*" GASB Statement No. 37 (GASBS 37), "*Basic Financial Statements and Management's Discussion and Analysis for State and Local Governments: Omnibus – an Amendment of GASB Statements No. 21 and No. 34*" and GASB Statement No. 38 "*Certain Financial Statement Note Disclosures*" (GASBS 38). GASBS 34, as amended, and GASBS 38 establish specific standards for external financial reporting for all state and local governments. As a result of adopting these Standards, the basic financial statement presentation was significantly changed, including adding management's discussion and analysis of operating, investing and financing activities. GASBS 34 also requires the classification of fund net assets into three components – invested in capital assets, net of related debt; restricted; and unrestricted. These classifications are defined as follows:

- Invested in capital assets, net of related debt – This component of net assets consists of capital assets, net of accumulated depreciation reduced by the outstanding debt balances, net of unamortized debt expenses.

- Restricted – This component consists of net assets with constraints placed on their use, either externally or internally. Constraints include those imposed by creditors (such as through debt covenants), grants or laws and regulations of other governments, or by law through constitutional provisions or enabling legislation or by the Board.

- Unrestricted – This component of net assets consists of net assets that do not meet the definition of "restricted" or "invested in capital, net of related debt."

Under GASBS 34, the statements of equity and of other comprehensive income were eliminated, the statement of income was renamed the statement of revenue, expenses and changes in fund net assets, and the statement of cash flows is required to be presented using the direct method (including a reconciliation of operating cash flows to operating income). Under GASBS 34, uncollectible debt expense was reclassified as a reduction of operating revenues.

NOTE 3: Regulatory Matters

Effective April 1, 1998, customers of California's investor-owned utilities (IOU) became eligible for direct access. The introduction of direct access resulted in significant structural changes to the electric power industry, including plant divestitures and management of IOU transmission assets through the California Independent System Operator (CISO). No definitive plan for allowing direct access to customers in the Department's service area has been adopted; however, if the Department implements direct access in the future, it is likely that its generation business will no longer qualify for accounting under SFAS No. 71. SFAS No. 71 requires that the effects of the ratemaking process be recorded in the financial statements. Based on current and projected market prices, management does not believe that market issues or the introduction of direct access will negatively impact the Department's financial position. In 2001, legislation was enacted to suspend direct access to retail customers in California.

As a government-owned utility, the Department was not compelled to participate in direct access or to divest its generation assets. Management continues to evaluate the Department's alternatives in response to deregulation, the introduction of direct access and participation in the CISO. In addition, management has implemented debt and cost reduction programs and restructured certain purchase power commitments in response to the changes in the electric utility market. Furthermore, in August 2000, the City Council approved a $1.7 billion, ten-year plan to upgrade the Department's local power plants and to implement a program that includes demand side management, alternative energy sources and distributed generation. This plan has been amended to allow for a total budget of $2.0 billion. Through June 30, 2003, the Department has incurred $930.8 million related to such upgrades.

Federal Energy Regulatory Commission Price Mitigation Plan

In June 2001, the Federal Energy Regulatory Commission (FERC) issued a price mitigation plan on spot market sales in the Western Electric Coordinating Council (WECC). The plan imposes price limits on the sale of electricity in WECC based on a calculation that estimates the cost of production of the least efficient gas-fired generation plant in California and a fixed factor to account for other variable costs. The calculation is based on factors existing at the then most current California Stage 1 Emergency. Sellers and other marketers have the opportunity to justify prices above the limit to the FERC. On July 17, 2002, FERC ordered effective October 1, 2002, among other things, a new price cap and certain automatic procedures in the WECC, designed to mitigate the effects of market power. Energy Services' purchases and sales of electricity occur entirely within the WECC and as such are subject to these measures. These measures have in part, contributed to stabilizing the market and resulting in overall lower wholesale prices.

NOTE 3: (continued)

California Receivables and FERC refund hearings

During fiscal year 2001, the Department made sales to two California agencies that were formed by Assembly Bill 1890 to facilitate the purchase and sale of energy and ancillary services in the State of California. Through June 30, 2003, these agencies, the CISO and the California Power Exchange (CPX), have made minimal payments since April 2001 on amounts outstanding to counterparties, including Energy Services, for certain energy purchases in fiscal years 2000 and 2001. The CPX filed for protection under Chapter 11 of the Federal Bankruptcy Statute in January of 2001. Two utilities with significant amounts due to these agencies, Southern California Edison Company and Pacific Gas & Electric, have previously stated in public disclosure documents that they may not be able to pay for all the power they consumed in 2001. Southern California Edison Company has paid all amounts due by it to the CPX, however the amounts remain in an escrow account pending the resolution of disbursement of the funds. Pacific Gas & Electric has filed for protection under Chapter 11 of the Federal Bankruptcy Statute and all amounts due from that entity are outstanding.

As of June 30, 2003 and 2002, a total of $168.7 and $170.4 million, respectively, was due to Energy Services from the CISO and the CPX. The FERC has questioned whether amounts charged for energy sold to the CISO and the CPX during 2000 and 2001 represent "unlawful profits" that should be subject to refund. The FERC has considered various options for determination of a refund amount but has not issued definitive guidance on what represents unlawful profits for sales during the period. If the FERC issues an order requiring a refund under defined conditions, the Department may be liable to refund a portion of amounts recorded as sales. However, it has not been established that the FERC has any jurisdiction over municipal utilities, including the Department.

Energy Services has recorded a $40.0 million liability as of June 30, 2003 against the $168.7 million receivable, for potential refunds pertaining to its wholesale sales during 2000 and 2001. Management believes that this is the most probable amount that will be paid by the Department and is based on the most recent formula disclosed by FERC. Energy Services estimated this amount to be $7.0 million in the prior year based on the best information available at the time and therefore recorded a reserve of $7.0 million as of June 30, 2002 against the $170.4 million receivable. While management has recorded its estimate of the most probable amounts that will be paid, management does believe that it is entitled to all amounts due from sales to counterparties in California, including those named above. Furthermore, management believes that interest may be due to it on those amounts but any potential receivable is not estimable at this time. In addition, management does not believe that Energy Services' exposure to any additional losses with respect to these receivable balances is currently estimable. If final settlement of these receivables results in an amount less than the recorded balance, net of the $40.0 million reserve, the Department will be required to record a loss in the statement of revenue, expenses and changes in fund net assets.

NOTE 3: (continued)

Public benefits

In accordance with Assembly Bill 1890, as amended by Assembly Bill 995 and pursuant to direction from the Board, a percentage of the Department's retail revenue is designated for use for qualifying public benefits programs. Qualifying programs include cost-effective demand side management services to promote energy-efficiency and energy conservation, new investment in renewable energy resources and technologies, development and demonstration programs to advance science and technology, and services provided for low-income electricity customers. In accordance with current legislation and the Department's plans, the program is currently expected to cease January 1, 2012.

The Department defers public benefits revenue from customers in excess of costs incurred under qualifying programs and defers qualifying expenses in excess of collections pursuant to approval received from the Board. During fiscal year 2003, Energy Services changed its public benefits deferral estimate. The change in estimate was the result of an updated interpretation of Assembly Bill 1890. As a result, the Department recorded an increase in its public benefits deferred credit balance of $27 million. During fiscal years 2003, 2002, and 2001, the Department spent $74.9, $65.8, and $63.5 million, respectively, on public benefits programs. These programs include investments in electric buses and vehicles, photovoltaics, or solar power and other alternative energy sources, and support for low-income and life support customers. As of June 30, 2003, the Department recorded a deferred expense of $11.7 million due to public benefit expenses incurred in excess of revenues. The deferred expenses at June 30, 2003 will be recognized when the corresponding revenue is earned. As of June 30, 2002, the Department deferred unspent public benefit revenues of $12.0 million.

Accounting for the State Energy Efficiency Grant

During fiscal year 2001, the Department was awarded a $16 million grant by the State of California for the purpose of reducing energy demand during the summer months. The Department received $8 million in fiscal year 2001 and the remaining $8 million in fiscal year 2002. Grant money received was initially recorded as a deferred credit on the balance sheet. As funds were disbursed on qualifying energy efficiency programs, Energy Services recognized the grant funds received as non-operating revenues, and recognized the expenditures as non-operating expenses. During fiscal years 2002 and 2001, the Department recognized $15 million and $1 million respectively of these grant funds as non-operating income. The entire grant was disbursed as of June 2002.

NOTE 4: Utility Plant

Energy Services had the following activity in utility plant during fiscal year 2003 (amounts in thousands):

	Balance June 30, 2002	Additions	Retirements and Disposals	Transfers	Reclassifications	Balance June 30, 2003
Nondepreciable utility plant						
Land and land rights	$ 154,368	$ -	$ (298)	$ -	$ 2,655	$ 156,725
Construction work in progress	379,970	492,369	-	(109,339)	-	763,000
Nuclear fuel**	16,943	8,058	(11,570)	-	-	13,431
Total nondepreciable utility plant	551,281	500,427	(11,868)	(109,339)	2,655	933,156
Depreciable utility plant						
Generation	2,605,232	11,990	(11,730)	7,652	-	2,613,144
Transmission	729,651	4,042	(1,581)	17,638	-	749,750
Distribution	3,667,305	101,065	(3,474)	79,933	(2,655)	3,842,174
General	840,587	61,369	(7,381)	4,116	-	898,691
Total depreciable utility plant	7,842,775	178,466	(24,166)	109,339	(2,655)	8,103,759
Less accumulated depreciation*	(3,828,328)	(285,214)	40,076	-	-	(4,073,466)
Total utility plant, net	$ 4,565,728	$ 393,679	$ 4,042	$ -	$ -	$ 4,963,449

* *Additions to accumulated depreciation include capitalized depreciation of $22.4 million.*

** *Nuclear fuel disposals represent amortization.*

NOTE 5: Jointly-Owned Utility Plant

Energy Services has direct interests in several electric generating stations and transmission systems, which are jointly-owned with other utilities. As of June 30, 2003, utility plant includes the following amounts related to Energy Services' ownership interest in each jointly-owned utility plant (amounts in thousands, except as indicated):

	Ownership Interest	Share of Capacity (MW)	Utility Plant in Service: Cost	Utility Plant in Service: Accumulated Depreciation
Palo Verde Nuclear Generating Station	5.7%	217	$ 514,284	$ 242,883
Navajo Generating Station	21.2%	477	210,205	199,063
Mohave Generating Station	10.0%	158	66,633	41,742
Pacific Intertie DC Transmission Line	40.0%	1240	192,277	55,217
Other transmission systems		Various	75,015	37,348
			$ 1,058,414	$ 576,253

NOTE 5: (continued)

Energy Services will incur certain minimum operating costs related to the jointly-owned facilities, regardless of the amount or its ability to take delivery of its share of energy generated. Energy Services' proportionate share of the operating costs of the joint plants is included in the corresponding categories of operating expenses.

On November 27, 2001, the Los Angeles City Council approved the sale of fifty percent of the Department's twenty percent ownership interest in the Mohave Generating Station to the Salt River Project Agricultural Improvement and Power District (SRP). SRP took the place of the original purchaser, AES Corporation, under the terms of the Mohave Project Plant Site Conveyance and Co-Tenancy Agreement. SRP paid $95 million in cash for the 10% interest. The sale resulted in the recognition of a gain of $67.6 million, which is included in other income and expense on the statements of revenue, expenses, and changes in fund net assets in fiscal year 2002.

NOTE 6: Purchase Power Commitments

The Department has entered into a number of energy and transmission service contracts, which involve substantial commitments as follows (amounts in thousands, except as indicated):

			Department's Interest in Agency's Share		
	Agency	Agency Share	Interest	Capacity MW	Outstanding Principal
Intermountain Power Project	IPA	100.0%	66.8%	1,068	$ 1,670,100
Palo Verde Nuclear Generating Station	SCPPA	5.9%	67.0%	151	$ 510,175
Mead-Adelanto Project	SCPPA	67.9%	35.7%	291	$ 81,828
Mead-Phoenix Project	SCPPA	17.8% - 22.4%	24.8%	148	$ 17,883
Southern Transmission System	SCPPA	100.0%	59.5%	1,142	$ 594,194

IPA: The Intermountain Power Agency is an agency of the State of Utah established to own, acquire, construct, operate, maintain, and repair the Intermountain Power Project (IPP). Energy Services serves as the Project Manager and Operating Agent of IPP.

SCPPA: The Southern California Public Power Authority, a California Joint Powers Agency. Note: SCPPA's interest in the Mead-Phoenix Project includes three components.

NOTE 6: (continued)

The above agreements require Energy Services to make certain minimum payments, which are based primarily upon debt service requirements. In addition to average annual fixed charges of approximately $295 million during each of the next five years, the Department is required to pay for operating and maintenance costs related to actual deliveries of energy under these agreements (averaging approximately $245 million annually during each of the next five years). The Department made total payments under these agreements of approximately $546, $514, and $532 million in fiscal years 2003, 2002 and 2001, respectively. These agreements are scheduled to expire from 2027 to 2030.

Energy Services earned fees under the IPP Project Manager and Operating agreements totaling $15.8, $14.7 and $14.0 million in fiscal years 2003, 2002 and 2001, respectively.

Long-term notes receivable

Under the terms of its purchase power agreement with IPA, the Department is charged for its output entitlements based on its share of IPA's costs, including debt service. During fiscal year 2000, the Department restructured a portion of this obligation by transferring $1.12 billion to IPA in exchange for long-term notes receivable. The funds transferred were obtained from the debt reduction trust funds and through the issuance of new variable rate debentures (see Notes 7 and 10). IPA used the proceeds from these transactions to defease and to tender for bonds with par values of approximately $615 and $611 million, respectively. The net discount of $114 million is being amortized using the effective interest method over the lives of the bonds through 2023.

On September 7, 2000, the Department transferred $187 million to IPA in exchange for additional long-term notes receivable. IPA used the proceeds to defease bonds with a face value of $198 million. The net discount of $9 million is being amortized using the effective interest method over the life of the bonds through 2017.

The IPA notes are subordinate to all of IPA's publicly held debt obligations. The Department's future payments to IPA will be partially offset by interest payments and principal maturities from the subordinated notes receivable. The net IPA notes receivable balance totaled $1.23 billion and $1.29 billion as of June 30, 2003 and 2002, respectively.

Energy entitlement

The Department has a contract through 2017 with the U.S. Department of Energy for the purchase of available energy generated at the Hoover Power Plant. The Department's share of capacity at Hoover is approximately 500 megawatts. The cost of power purchased under this contract was $11 million in each of fiscal years 2003, 2002 and 2001.

NOTE 7: Restricted and Other Investments

A summary of Energy Services' restricted and other investments is as follows (amounts in thousands):

	June 30,	
	2003	2002
Restricted and other investments:		
Escrow investments	$ 34,262	$ 33,714
Debt reduction trust funds	836,427	807,748
Nuclear decommissioning trust funds	90,576	85,586
Other investments	43,107	139,934
Total Restricted and other investments	$ 1,004,372	$ 1,066,982
Other:		
Cash collateral received from securities lending transactions (see Note 8)	$ 243,361	$ 187,180
Postretirement health care benefit trust fund	131,247	62,727
Total	$ 1,378,980	$ 1,316,889

All restricted and other investments are held in trust accounts to be used for a designated purpose as follows:

Escrow investments

Escrow investments are held to call specified revenue bonds at scheduled maturity dates.

Debt reduction trust funds

The debt reduction trust funds were established during fiscal year 1997 to provide for the payment of principal and interest on long-term debt obligations and purchased power obligations arising from the Department's participation in the Intermountain Power Project and the Southern California Public Power Authority (SCPPA) (see Note 6). The Department has transferred funds from purchased power pre-collections into these trust funds. Funds from operations may also be transferred by management as funds become available.

Nuclear decommissioning trust funds

Nuclear decommissioning trust funds will be used to pay the Department's share of decommissioning the Palo Verde Nuclear Generating Station at the end of its useful life (see Note 1).

NOTE 7: (continued)

Postretirement health care benefit trust fund

The postretirement health care benefit trust fund was established to provide for the payment of the Department's postretirement health benefits. Accrued postretirement liabilities are recorded net of the trust fund (see Note 12).

Other investments

Other investments consist of funds held by SCPPA on behalf of the Department. Certain of these investments are currently being used by the Department to provide for the payment of principal and interest on long-term debt obligations and purchased power obligations arising from the Department's participation in SCPPA. However, there are no restrictions imposed on the Department regarding the use of these investments.

Restricted and other investments held by the Department are categorized separately below to give an indication of the level of custodial credit risk assumed by the Department. Specifically, identifiable investments are classified as to credit risk by three categories and summarized below as follows: Category 1 includes investments that are insured or registered or for which securities are held by the Department or its agent in the Department's name; Category 2 includes uninsured and unregistered investments for which the securities are held by the counterparty's trust department or agent in the Department's name; and Category 3 includes uninsured and unregistered investments for which the securities are held by the counterparty or by its trust department or agent, but not in the Department's name.

NOTE 7: (continued)

At June 30, 2003, Energy Services' restricted and other investments are categorized as follows (amounts in thousands):

Type of Investments	Category 1	Category 2	Category 3	Total
Investments - categorized				
U.S. government securities	$ 510,281	$ -	$ -	$ 510,281
Bonds	162,375	-	-	162,375
Commercial paper	216,534	-	-	216,534
Repurchase agreements	-	218,666	-	218,666
Negotiable certificates of deposits	33,312	-	-	33,312
Total categorized restricted and other investments	$ 922,502	$ 218,666	$ -	$ 1,141,168
Investments - not categorized				
Investments held by broker-dealers:				
U.S. government securities				212,855
Mutual funds				262
General pooled securities lending cash collateral				24,695
Total				$ 1,378,980

At June 30, 2002, Energy Services' restricted and other investments are categorized as follows (amounts in thousands):

Type of Investments	Category 1	Category 2	Category 3	Total
Investments - categorized				
U.S. government securities	$ 641,375	$ -	$ -	$ 641,375
Bonds	249,262	-	-	249,262
Commercial paper	41,944	-	-	41,944
Repurchase agreements	-	155,212	-	155,212
Negotiable certificates of deposits	39,203	-	-	39,203
Total categorized restricted and other investments	$ 971,784	$ 155,212	$ -	$ 1,126,996
Investments - not categorized				
Investments held by broker-dealers:				
U.S. government securities				151,459
Mutual funds				6,465
General pooled securities lending cash collateral				31,969
Total				$ 1,316,889

Repurchase agreements relate to the Department's securities lending program (see Note 8).

NOTE 8: Securities Lending Transactions

In December 1999, the Department initiated a securities lending program managed by its custodial bank. The bank lends up to 20% of the investments held in the debt reduction trust funds, decommissioning trust funds, and plan assets held in the postretirement benefits trust fund for securities, cash collateral or letters of credit equal to 102% of the market value of the loaned securities and interest, if any. The Department can sell collateral securities only in the event of borrower default. Both the investments purchased with the collateral received and the related liability to repay the collateral are reported on the balance sheets. A summary of Energy Services' securities lending transactions as of June 30, 2003 and 2002 is as follows (amounts in thousands):

	June 30, 2003		June 30, 2002	
Securities lent for cash collateral	Fair value of underlying securities	Collateral value	Fair value of underlying securities	Collateral value
US Government and agency securities	$ 213,199	$ 218,667	$ 151,782	$ 155,211

Cash collateral received is reinvested by the lending agent in open repurchase agreements. As such, the maturities of reinvested cash collateral always match the maturities of the underlying securities lent. The lending agent provides indemnification for borrower default. There were no violations of legal or contractual provisions and no borrower or lending agent default losses during fiscal years 2003 and 2002.

General Investment Pool Program

The Department also participates in the City's securities lending program through the pooled investment fund. The City's program has substantially the same terms as the Department's direct securities lending program. The Department recognizes its proportionate share of the cash collateral received for securities loaned and the related obligation for the general investment pool. As of June 30, 2003 and 2002, Energy Services' attributed share of cash collateral and the related obligation from the City's program was $24.7 and $32.0 million, respectively.

Management believes that participation in these securities lending programs results in no credit risk exposure to the Department because the amounts owed to the borrowers exceed the amounts the borrowers owe to the Department and the Pool.

NOTE 9: Derivative Instruments

As a result of the Department's change in election under GASBS No. 20 (see Note 2), Energy Services no longer records its derivative instruments at fair value on the balance sheets. Energy Services has four main types of derivative instruments as of June 30, 2003: electricity forward contracts, electricity swaps, electricity option and swaption contracts, and gas forward contracts.

Objective of electricity forward contracts

The Department routinely enters into electricity forward contracts to manage its requirements to service its electric customers. Forward contracts to buy or sell energy scheduled for delivery in future periods generally qualify as derivative instruments as described in GASB Technical Bulletin 2003-1, *"Disclosure Requirements for Derivatives Not Reported at Fair Value on the Statement of Net Assets,"* (GTB 2003-1) which utilizes the definitions embodied in SFAS No. 133.

Objective of electricity swaps, options and swaptions

In order to obtain the highest market value on energy that is sold into the wholesale market, the Department monitors the sales price of energy which varies based on which hub the energy is to be delivered. There are three primary hubs within the Department's transmission region: Palo Verde, California-Oregon Border and Mead. The Department enters into various locational swap transactions with other electric utilities in order to effectively utilize its transmission capacity and to achieve the most economical exchange of energy purchased and sold.

A call option is the right, but not the obligation, to buy energy at a fixed price on or before a specific date. Because the Department has excess electric generation available as certain times during the year, it sells call options for a premium to other utilities. If the buyer calls the option, the Department is obligated to sell the energy for a specified dollar amount and deliver it to a specific delivery point. If the buyer does not call the option, the Department has no obligation to deliver energy, but does retain the premium paid. Premiums received are deferred and amortized to income over the period the option is outstanding and are recorded as part of Sales for Resale revenue. As of June 30, 2003, Energy Services has recorded $1.3 million of deferred option revenue relating to options and swaptions entered into prior to the fiscal year end.

Objective of gas forward contracts

The Department enters into gas forward contracts in order to supply its gas requirements to produce electricity to serve its customers. The Department does not routinely enter into sale or swap transactions for gas. Through fiscal year 2003, all gas transactions entered into by the Department were physical transactions.

NOTE 9: (continued)

Certain of the derivatives described above qualify as an exception provided under GTB 2003-1 for activities that are considered normal purchases and normal sales. These transactions are excluded from the scope of GTB 2003-1.

As of June 30, 2003, Energy Services had the following derivatives which were not recorded at fair value on its balance sheet:

Derivative Description	Total Contract Quantities	Contract Price Range $ per Unit	First Effective Date	Last Termination Date	Fair Value ($000's)	Cash received at derivative inception ($000's)
Electricity swaps						
Puchases *	110,451 MW	59.00 - 70.25	7/1/03	9/30/03	(219)	$ -
Sales *	110,451 MW	63.60 - 78.00	7/1/03	9/30/03	71	82
Electricity swaption contract	30,800 MW	78.00	7/1/03	9/30/03	242	601
Electricity option contracts						
Sales **	87,640 MW	76.49 - 95.00	7/1/03	9/30/03	2,963	937
Gas contract ***	49,500,000 MMBtu	3.76 - 5.18	3/15/91	3/15/06	(2,736)	-

** The swap contracts include one contract with a price partially dependent on the SoCal Border Daily Gas Index, which averaged $5.10 per MMBtu as of June 30, 2003 for the forward period of July 1, 2003 - September 30, 2003.*

*** The electricity option contracts include one contract with a price that is dependent on the SoCal Border Daily Gas Index, which averaged $5.10 per MMBtu as of June 30, 2003 for the forward period of July 1, 2003 - September 30, 2003.*

**** The gas contract quantities represent the contract maximum of 50,000 MMBtu per day. Contract prices are based in part on Gas Price Indices, Including Henry Hub and Kern River Prices.*

Fair value

As a result of forward wholesale electricity prices being in excess of contract prices as of June 30, 2003, all of the Department's electric sale derivative contracts generally had positive fair values, and the electric purchase derivative contracts generally had negative fair values. All fair values were estimated using forward market prices available from broker quotes or exchange prices in the case of the gas contract.

NOTE 9: (continued)

Credit Risk

Energy Services is exposed to credit risk related to nonperformance by its wholesale counterparties under the terms of these contractual agreements. In order to limit the risk of counterparty default, the Department has implemented a Wholesale Marketing Counterparty Evaluation Policy (the Policy). The Policy includes provisions to limit risk including: the assignment of internal credit ratings to all Department counterparties based on counterparty and/or debt ratings; the requirement for credit enhancements (including irrevocable letters of credit, escrow trust accounts and parent company guarantees) for counterparties that do not meet an acceptable level of risk; and the use of standardized agreements which allow for the netting of positive and negative exposures associated with a single counterparty. As discussed in Note 3, during fiscal year 2001, Energy Services experienced nonperformance and material counterparty default with the CISO and the CPX. Energy Services does not anticipate nonperformance by any other of its counterparties and has no reserves related to nonperformance at June 30, 2003 and 2002, respectively. Apart from the events discussed in Note 3, Energy Services did not experience any material counterparty default during fiscal years 2003, 2002 or 2001.

Termination Risk

Energy services or its counterparties may terminate the contractual agreements if the other party fails to perform under the terms of the contract.

NOTE 10: Long-term Debt

Long-term debt outstanding as of June 30, 2003 consists of revenue bonds and refunding revenue bonds due serially in varying annual amounts as follows (amounts in thousands):

Bond Issues	Date of Issue	Effective Interest Rate	Fiscal Year of Last Scheduled Maturity	Principal Outstanding
Refunding Issue of 1993	04/15/93	5.824%	2031	$ 499,175
Second Refunding Issue of 1993	11/15/93	5.424%	2032	493,690
Issue of 2000	03/02/00	5.945%	2030	64,780
Issue of 2001, Series A1	03/20/01	4.931%	2025	1,140,665
Issue of 2001, Series A2	11/06/01	5.109%	2022	109,095
Issue of 2001, Series A3	04/01/01	5.095%	2025	116,295
Issue of 2001, Series B	06/05/01	Variable	2035	620,600
Issue of 2001, Series C1	11/15/01	4.744%	2017	5,630
Issue of 2002, Series A	08/22/02	Variable	2036	388,500
Issue of 2002, Series C2	11/22/02	4.375%	2018	13,850
	Total principal amount			3,452,280
	Unamortized debt-related costs (including net loss on refundings)			(57,012)
	Debt due within one year (including current portion of variable rate debt)			(163,180)
				$ 3,232,088

Revenue bonds generally are callable ten years after issuance. The Department has agreed to certain covenants with respect to bonded indebtedness. Significant covenants include the requirement that Energy Services' net income, as defined, will be sufficient to pay certain amounts of future annual bond interest and of future annual aggregate bond interest and principal maturities. Revenue bonds and refunding bonds are collateralized by the future revenues of Energy Services.

NOTE 10: (continued)

Long term debt activity

Energy Services had the following activity in long-term debt during fiscal year 2003 (amounts in thousands):

	Balance at June 30, 2002	Additions	Reductions	Balance at June 30, 2003	Current Portion
Long term debt	$ 3,281,858	$ 402,385	$ (452,155)	$ 3,232,088	$ 163,180

New issuances

Fiscal Year 2003

In August 2002, the Department issued $388.5 million of Energy Services variable rate bonds for the purpose of defeasing outstanding commercial paper. The net proceeds from the issuance were deposited into a trust and were used to secure the new bonds until September 2002 at which time the commercial paper was paid. The purpose of the defeasance was to bring the variable rate debt under Energy Services' new Master Bond Resolution. The defeasance is not expected to reduce total debt payments over the life of the new issues nor to result in present value savings.

In November 2002, the Department issued $14 million of Energy Services fixed rate bonds as part of the Mini-Bond Program for employees and retirees. Energy Services' Mini-Bond Program allows for a maximum total issuance of $50 million. The net proceeds were deposited into the construction fund to be used for distribution system capital improvements.

Furthermore, in July and August 2003, Energy Services issued $956 million and $200 million of Power System Revenue Bonds, respectively. The July 2003 bonds were issued for the purpose of refunding portions of the Refunding Issue of 1993, the Second Issue of 1993 and the Issue of 2000. The August 2003 bonds were issued for the purpose of electric system capital improvements.

NOTE 10: (continued)

Fiscal Year 2002

In June 2001, the Department issued $621 million of Energy Services variable rate bonds for the purpose of defeasing the Second Issue of 2000 bonds in August 2001. The net proceeds from the issuance were deposited into a trust and were used to secure the new bonds until August 2001 at which time the Second Issue of 2000 bonds were defeased. The purpose of the defeasance was to bring the variable rate bonds under Energy Services' new Master Bond Resolution. The defeasance is not expected to reduce total debt payments over the life of the new issues nor to result in present value savings. This transaction resulted in a net gain for accounting purposes of $2 million, which was deferred and is being amortized through 2010.

In November 2001, the Department issued $109 million of Energy Services fixed rate bonds. The net proceeds were used to defease bonds with a par value of $107 million. The defeasance is expected to reduce total debt payments over the life of the new issues by $21 million and is expected to result in present value savings of approximately $8 million. This transaction resulted in a net loss for accounting purposes of $5 million, which was deferred and is being amortized through 2021.

In November 2001, the Department issued $7 million of Energy Services fixed rate bonds as part of the Mini-Bond Program for employees and retirees. The net proceeds were deposited into the construction fund to be used for distribution system capital improvements.

Outstanding debt defeased

As discussed above, Energy Services defeased certain revenue bonds in prior years by placing cash or the proceeds of new revenue bonds in irrevocable trusts to provide for all future debt service payments on the old bonds. Accordingly, the trust account assets and the liability for the defeased bonds are not included in Energy Services' financial statements.

NOTE 10: (continued)

At June 30, 2003, the following revenue bonds outstanding are considered defeased (amounts in thousands):

Bond Issues	Principal Outstanding
Third Issue of 1991	$ 1,265
Issue of 1992	2,285
Second Issue of 1993	118,600
Refunding Issue of 1993	43,965
Refunding Issue of 1994	117,310
Issue of 1994	79,800
Issue of 1999	180,000
Issue of 2000	186,365
	$ 729,590

Variable rate bonds

The variable rate bonds currently bear interest at daily and weekly rates (ranging from 0.97% to 1.05% as of June 30, 2003). The Department can elect to change the interest rate period of the bonds, with certain limitations. The bondholders have the right to tender the bonds to the tender agent on any business day with seven days prior notice. The Department has entered into Standby Agreements with a syndicate of commercial banks in an initial amount of $620.6 million and $388.5 million to provide liquidity for these bonds. The extended Standby Agreements expire on February 19, 2004 and February 26, 2004 for the $620.6 million issue and on August 27, 2004 for the $388.5 million issue.

Bonds purchased under the agreements will bear interest that is payable quarterly at the greater of the Federal Funds Rate plus 0.50% or the bank's announced base rate, as defined. The unpaid principal of bonds purchased is payable in ten equal semi-annual installments, commencing after the termination of the agreement. At its discretion, the Department has the ability to convert the outstanding bonds to fixed rate obligations, which cannot be tendered by the bondholders. These bonds have been classified as long term on the balance sheets as the liquidity facilities give the Department the ability to refinance on a long term basis and the Department intends to either renew the facility or exercise its right to tender the debt as a long term financing. That portion which would be due in the next fiscal year in the event that the outstanding variable rate bonds were tendered and purchased by the commercial banks under the Standby Agreements, has been included in the current portion of long term debt and was $100.9 million as of June 30, 2003 and 2002.

NOTE 10: (continued)

Advance refunding bonds and escrow investments

In prior years, Energy Services established irrevocable escrow trusts with proceeds from the issuance of refunding bonds. During fiscal year 2002, bonds with a par value of $240 million were refunded using proceeds from the balance in the restricted escrow investments. During fiscal 2002, all remaining advance refunding bonds were reclassified to long-term debt as the bonds to be refunded were called.

In July 2000, the Department deposited $32 million into a trust established for the purpose of making future debt service payments on specified revenue bonds with a par value of $35 million. The final maturity of the related revenue bonds is 2031. The escrow balance was $34.3 and $33.7 million (stated at fair value as of June 30, 2003 and 2002, respectively). Interest expense from the related bonds and interest income earned on the related escrow investments are included in investment income.

Revenue certificates

As of June 30, 2002, the Department had outstanding commercial paper of $388.5 million bearing interest at an average rate of 1.40%. In August 2002, the Department repaid the commercial paper using proceeds from the issuance of $388.5 million in variable rate debt as described above.

Scheduled principal maturities and interest

Scheduled annual principal maturities and interest are as follows (amounts in thousands):

Fiscal years ending June 30,	Principal	Interest and Amortization
2004	$ 62,270	$ 138,227
2005	75,518	133,856
2006	69,886	130,094
2007	67,568	126,897
2008	40,413	124,829
2009 - 2013	471,036	562,884
2014 - 2018	489,789	409,579
2019 - 2023	687,520	261,665
2024 - 2028	619,710	101,558
2029 - 2033	566,820	32,320
2034 - 2036	301,750	2,352
Total Requirements	$ 3,452,280	$ 2,024,261

NOTE 10: (continued)

The scheduled maturities for the fiscal year ending June 30, 2004 exclude $100.9 million in variable rate bonds classified as short term for reporting purposes as described above. Interest and amortization includes interest requirements for variable rate debt, using the average variable debt interest rate in effect at June 30, 2003 of 1.01%.

Fair value

The fair value of long-term debt is $3.2 and $2.7 billion at June 30, 2003 and 2002, respectively. Management has estimated fair value based on the present value of interest and principal payments on the long-term debt and refunding bonds, discounted using current interest rates obtainable by the Department for debt of similar quality and maturities.

NOTE 11: Retirement, Disability and Death Benefit Insurance Plan

The Department has a funded contributory retirement, disability and death benefit insurance plan covering substantially all of its employees. The Water and Power Employees' Retirement, Disability and Death Benefit Insurance Plan (the Plan) operates as a single-employer benefit plan to provide pension benefits to eligible Department employees and to provide disability and death benefits from the respective insurance funds. Plan benefits are generally based on years of service, age at retirement and the employee's highest 12 consecutive months of salary before retirement. Active participants who joined the Plan on or after June 1, 1984 are required to contribute 6% of their annual covered payroll. Participants who joined the Plan prior to June 1, 1984 contribute an amount based upon an entry-age percentage rate. The Department contributes $1.10 for each $1.00 contributed by participants plus an actuarially determined annual required contribution as determined by the Plan's independent actuary. The contributions are allocated between Energy Services and Water Services based on the current year labor costs.

The Retirement Board of Administration (the Retirement Board) is the administrator of the Plan. The Plan is subject to provisions of the Charter of the City of Los Angeles and the regulations and instructions of the Board of Water and Power Commissioners (the Board of Commissioners). The Plan is an independent pension trust fund of the Department.

Plan amendments must be approved by both the Retirement Board and the Board of Commissioners. The Plan issues separately available financial statements on an annual basis.

NOTE 11: (continued)

Energy Services' allocated share of annual pension cost (APC) and net pension obligation (NPO) consists of the following (amounts in thousands):

	Year Ended June 30,	
	2003	2002
Annual required contribution	$ 31,560	$ -
Interest on net pension asset	(10,750)	(9,134)
Adjustment to annual required contribution	16,017	14,120
APC (including $9.1 and $1 million of amounts capitalized in fiscal 2003 and 2002, respectively)	36,827	4,986
Department contributions	(25,441)	(17,900)
Shared operating expenses (see Note 13)	(4,929)	(479)
Change in NPO	6,457	(13,393)
NPO (asset) at beginning of year	(125,655)	(112,262)
NPO (asset) at end of year	$ (119,198)	$ (125,655)

Annual required contributions are determined through actuarial valuations using the entry age normal actuarial cost method. The actuarial value of assets in excess of the Department's actuarial accrued liability (AAL) was being amortized by level contribution offsets over the period ending June 30, 2003. As a result of an April 2000 amendment to the Plan, the amortization period was changed to rolling fifteen-year periods effective July 1, 2000.

In accordance with actuarial valuations, the Department's required contribution rates are as follows:

Acturial Valuation Date June 30	Normal Cost	Surplus Amortization	Contribution Rate
2002	10.97%	-2.64%	8.66%
2001	10.64%	-13.65%	0.00%
2000	10.59%	-14.52%	0.00%

The significant actuarial assumptions include an investment rate of return of 8%, projected inflation-adjusted salary increases of 5.5%, and postretirement benefit increases of 3%. The actuarial value of assets is determined using techniques that smooth the effects of short-term volatility in the market value of investments over a four-year period. Plan assets consist primarily of corporate and government bonds, common stocks, mortgage-backed securities and short-term investments.

NOTE 11: (continued)

Trend information for fiscal years 2003, 2002 and 2001 for Energy Services is as follows (amounts in thousands):

Year ended June 30,	NPO (asset)	Percentage of APC Contributed	APC
2003	$ (119,198)	84%	$ 36,827
2002	$ (125,655)	400%	$ 4,986
2001	$ (112,262)	413%	$ 4,526

The following schedule provides information about the Department's overall progress made in accumulating sufficient assets to pay benefits when due, prior to allocations to Water Services and Energy Services (amounts in thousands):

Actuarial Valuation Date June 30,	Actuarial Value of Assets	AAL	Actuarial Assets over AAL	Funded Ratio	Covered Payroll	Overfunding as a % of Covered Payroll
2002	$ 5,790,263	$ 5,714,525	$ 75,738	101%	$ 430,398	18%
2001	$ 5,833,275	$ 5,306,263	$ 527,012	110%	$ 403,266	131%
2000	$ 5,605,856	$ 5,082,960	$ 522,896	110%	$ 369,509	142%

Disability and death benefits

Energy Services' allocated share of disability and death benefit plan costs and administrative expenses totaled $11, $10, and $7 million for each of the fiscal years 2003, 2002, and 2001, respectively.

NOTE 12: Health Care Costs

The Department provides certain health care benefits to active and retired employees and their dependents. The health plan is administered by the Department, and the Retirement Board and the Board of Water and Power Commissioners have the authority to approve provisions and obligations. Eligibility for benefits is dependent on a combination of age and service of the participants pursuant to a predetermined formula. Any changes to these provisions must be approved by the Board. The Department pays a maximum subsidy of health plan premiums. Participants choosing plans with a cost in excess of the subsidy are required to pay the difference. The total number of active and retired Department participants entitled to receive benefits was approximately 14,200 at June 30, 2003.

The allocated cost to Energy Services of providing such benefits amounted to $134, $109, and $89 million for fiscal years 2003, 2002 and 2001, respectively. Of these costs, $33, $26, and $20 million were capitalized and the remainder was charged to expense for fiscal years 2003, 2002 and 2001, respectively.

Postretirement benefits

The Department accounts for postretirement benefits in accordance with SFAS No. 106, *"Employers' Accounting for Postretirement Benefits Other Than Pensions"*, which requires that the cost of postretirement benefits be recognized as expense over employees' service periods.

NOTE 12: (continued)

Energy Services' allocated share of postretirement benefit costs is summarized as follows (amounts in thousands):

	Year ended June 30,		
	2003	2002	2001
Service cost	$ 13,281	$ 10,829	$ 8,245
Interest cost	43,958	37,549	31,718
Expected return on plan assets	(2,645)	(2,614)	(2,560)
Amortization of transition obligation	9,979	9,994	9,994
Amortization of prior service costs	9,231	5,081	5,081
Amortization of actuarial losses	5,073	5,400	-
	$ 78,877	$ 66,239	$ 52,478

The funded status and the accrued benefit cost related to postretirement benefits for the Department, prior to allocations to Water Services and Energy Services, are summarized as follows (amounts in thousands):

	June 30,	
	2003	2002
Change in benefit obligation:		
Benefit obligation at beginning of year	$ 941,626	$ 802,849
Service cost	20,154	16,407
Interest cost	66,704	56,893
Actuarial losses	846,000	101,713
Benefits paid	(43,132)	(36,236)
Benefit obligation at end of year	1,831,352	941,626
Change in fair value of plan assets:		
Fair value of plan assets at beginning of year	81,493	77,669
Department contribution	96,000	-
Actual return on plan assets	7,232	3,824
Fair value of plan assets at end of year	184,725	81,493
Funded status	1,646,627	860,133
Unrecognized net loss	1,124,256	295,221
Unrecognized transition obligation	152,721	167,863
Unrecognized prior service cost	39,771	47,469
Accrued benefit cost	$ 329,879	$ 349,580
Energy Services' allocated share of accrued postretirement liability	$ (230,693)	$ (244,190)

NOTE 12: (continued)

Weighted average actuarial assumptions used in determining postretirement benefit costs are as follows:

	June 30,		
	2003	2002	2001
Discount rate	5.75%	7.25%	7.25%
Expected return on plan assets	6.25%	6.50%	6.50%

Plan assets consist primarily of commercial paper, United States government and governmental agency securities, and corporate bonds. In addition to having set up a trust fund, the Department currently pays benefits on a "pay as you go" basis. No funding policy has been established for the future benefit to be provided under this plan, however in fiscal year 2003, the Department made an employer contribution of $96 million.

For measurement purposes, a 10.0% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2003; the rate was assumed to decrease gradually to 5.5% in 2012 and remain at that level thereafter. For the dental plan, an 8.0% annual rate of increase in the per capita cost was assumed for 2003; the rate was assumed to decrease gradually to 5.5% in 2008 and remain at that level thereafter. The effect of a 1% change in these assumed health care cost trend rates would increase or decrease the Department's total benefit obligation by approximately $387 or $298 million, respectively. In addition, such a 1% change would increase or decrease the aggregate service and interest cost components of net periodic benefit cost by approximately $13 or $10 million, respectively.

During fiscal year 2000, the Department began contributing toward dental coverage for retirees enrolled in a Department-sponsored plan. This amendment resulted in a $46 million increase in the Department's accumulated postretirement benefit obligation at June 30, 2000. Energy Services' allocated $35 million share of this increase is being amortized through 2008, the remaining average service period. This change also resulted in an $12, $12 and $11 million increase in postretirement benefit costs for fiscal years 2003, 2002 and 2001, respectively, of which $8, $8 and $7 million, respectively, was allocated to Energy Services.

NOTE 13: Shared Operating Expenses

Energy Services shares certain administrative functions with the Department's Water Services. Generally, the costs of these functions are allocated on the basis of the benefits provided. Operating expenses shared with Water Services were $603, $514 and $455 million for fiscal years 2003, 2002 and 2001, respectively, of which $384, $328 and $301 million were allocated to Energy Services.

NOTE 14: Loss on Asset Impairment and Abandoned Project

During fiscal year 2001, management approved the sale of one of its administrative facilities and Energy Services reported its portion of the loss on asset impairment of $28 million. The completion of the sale was expected to occur within 12 to 24 months for a total original purchase price of $50 million, which was below the total asset carrying value. During fiscal year 2002, management became aware that the facility has mold in the structure. Management and the purchaser of the facility each conducted a study to determine an estimated cost for mold cleanup. As of June 30, 2002, no estimate was available to record a clean-up liability, however, as of June 30, 2003, management approved the sale of this administrative building for a reduced price of $37 million, which is pending Board approval. This reduction in price caused Energy Services to recognize an additional loss of $8.3 million as of June 30, 2003.

NOTE 15: Commitments and Contingencies

Transfers to the reserve fund of the City of Los Angeles

Under the provisions of the City Charter, Energy Services transfers funds at its discretion to the reserve fund of the City. Pursuant to covenants contained in the bond indentures, the transfers may not be in excess of the increase in fund net assets before transfers to the reserve fund of the City, of the prior fiscal year. Such payments are not in lieu of taxes and are recorded as a non-operating expense in the statement of revenue, expenses, and changes in fund net assets.

The Department authorized total transfers of $185.4, $179.2 and $119.8 million in fiscal years 2003, 2002 and 2001, respectively, from Energy Services to the reserve fund of the City. In 2002 and 2003, the Department authorized additional transfers of $25.0 and $29.0 million respectively, which was accrued as a liability as of fiscal year end. The $25.0 million accrued as of June 30, 2002 was paid in fiscal year 2003. The $29.0 million accrued as of June 30, 2003 was paid in July 2003. The Department expects to make an additional transfer declaration from Energy Services of approximately $150.2 million during fiscal year 2004.

Palo Verde Nuclear Generating Station (PVNGS) matters

As a joint project participant in PVNGS, the Department has certain commitments with respect to nuclear spent fuel and waste disposal. Under the Nuclear Policy Act, the Department of Energy (the DOE) was to develop the facilities necessary for the storage and disposal of spent fuel and to have the first such facility in operation by 1998; however, the DOE has announced that such a repository cannot be completed before 2010. There is ongoing litigation with respect to the DOE's ability to accept spent nuclear fuel; however, no permanent resolution has been reached.

NOTE 15: (continued)

In July 2002, a measure was signed into law designating the Yucca Mountain in the State of Nevada, as the nation's high-level nuclear waste repository. This means the DOE can now file a construction and operation plan for Yucca Mountain with the Nuclear Regulatory Commission (the NRC). The DOE expects that the Yucca Mountain site would be open by 2010, a date which many believe is highly optimistic. The State of Nevada and its congressional delegation have vowed to prevent the launch of the project through the NRC process or through legal challenges.

Disagreement over funding of the repository is ongoing. The Administration and Congressional leaders continue to push for full and adequate funding, in order for the DOE to meet the application deadline of 2004. The Nevada delegation has been working diligently to try to delay the DOE's work on the license application for the Yucca site in hopes of halting the transfer of nuclear waste to the Nevada facility.

Capacity in existing fuel storage pools at PVNGS were exhausted in 2003. A Dry Cask Storage Facility (also called the Independent Spent Fuel Storage Facility) was built and completed in 2003 at a total cost of $33.9 million (about $3.3 million for the Department). In addition to the facility, the costs also account for heavy lift equipment inside the units and at the yard, railroad track, tractors, transporter, transport canister, and surveillance equipment. The facility has the capacity to store all the spent fuel generated by the plant until 2026, the end of its lifetime. To date, five casks, each containing 24 fuel assemblies, from Unit 2 were placed in the Storage Facility. Moving of the spent fuel from Unit 1 to the Storage Facility is in progress. The current plan calls for the removal of between 240 and 288 fuel assemblies from the units to the Storage Facility every year. The costs incurred by the procurement, packing, preparation and transportation of the casks are included as part of the fuel expenses, and would cost approximately $12 million a year (about $1.2 million for the Department). If the permanent repository in Yucca Mountain is opened as scheduled in 2010, the spent fuel from PVNGS will be shipped to the repository starting in 2031. The Department accrues for current nuclear fuel storage costs as a component of fuel expense as the fuel is burned. The Department's share of spent nuclear fuel costs related to its indirect interest in PVNGS is included in purchased power expense.

NOTE 15: (continued)

The Price-Anderson Act (the Act) requires that all utilities with nuclear generating facilities share in payment for claims resulting from a nuclear incident. The Act limits liability from third-party claims to over $9.5 billion per incident. Participants in PVNGS currently insure potential claims and liability through commercial insurance with a $300 million limit; the remainder of the potential liability is covered by the industry-wide retrospective assessment program provided under the Act. This program limits assessments to a maximum of $100.6 million for each licensee for each nuclear incident occurring at any nuclear reactor in the United States; payments under the program are limited to $10 million per incident, per year. Based on the Department's 5.7% direct interest and its 3.95% indirect investment interest through SCPPA, the Department would be responsible for a maximum assessment of $9 million per incident, limited to payments of $1 million per incident annually.

Environmental matters

Numerous environmental laws and regulations affect Energy Services' facilities and operations. The Department monitors its compliance with laws and regulations and reviews its remediation obligations on an ongoing basis.

The Department's generating station facilities are subject to the Regional Clean Air Incentives Market (RECLAIM) nitrogen oxide (NOx) emission reduction program adopted by the South Coast Air Quality Management District (SCAQMD). In accordance with this program, SCAQMD established annual NOx allocations for NOx RECLAIM facilities based on historical emissions and type of emission sources operated. These allocations are in the form of RECLAIM trading emission credits (RTCs). Facilities that exceed their allocations may buy RTCs from other companies that have emissions below their allocations. The Department has a program of installing emission controls and purchasing RTCs, as necessary, to meet its emission requirements.

Based on the Department's significant increase in sales for resale during the spring and the early summer of 2000, the Department anticipated a potential shortfall in RTCs to provide for both its native load and the demands of the California grid during the remaining months of calendar year 2000. As a result, during August 2000, the Department entered into a settlement agreement (the Agreement) with the SCAQMD. The Agreement released the Department from any and all claims or penalties arising from the incidents which gave rise to the RECLAIM violations at its local facilities through December 31, 2000. The Agreement also provides for a civil penalty of not less than $14 million. The civil penalty must be spent within a three-year period on supplemental environmental projects agreed to by the SCAQMD and the Department.

NOTE 15: (continued)

Although the Department did not have a shortfall of RTCs at the end of calendar year 2000, the Department has continued its partnership with SCAQMD in the Department's funding of environmental projects. The Department and SCAQMD have agreed to projects in the areas of micro-turbine development and commercialization, natural gas fueling station infrastructure, tree plantings at schools, advanced fuel cell demonstration, and hybrid-electric midsize school buses.

In May 2001, SCAQMD adopted amendments to RECLAIM with the intent of lowering and stabilizing RTC prices. One key element of the amendments is that existing power plants are bifurcated from the rest of the RECLAIM market and are required to install Best Available Retrofit Control Technology (BARCT) through compliance plans. The Department submitted its compliance plans for SCAQMD approval in August 2001 that demonstrate that the Department has sufficient RTCs to meet its needs for the next five years; operates its generating units using "environmental dispatch"; and has installed BARCT or better on all sources of NOx emissions, or will do so by January 2003. Thus, the Department has established a program of installing NOx control equipment and repowering existing generating units with more efficient, cleaner equipment such that expected NOx emissions will be reduced by 65 percent from 1999 levels.

Capital expenditures

Energy Services has budgeted approximately $790 million of capital expenditures for fiscal year 2004.

Litigation

Claims and a lawsuit for damages have been filed with the Department, IPA and SCPPA seeking $100 million in special damages and a like amount in general damages. The claimants allege, among other things, that due to improper grounding of the transmission line of STS, their dairy herds were damaged and the value of their land was diminished. The claimants also seek injunctive relief. The Department, IPA and SCPPA intend to vigorously defend the claims.

A number of claims and suits are also pending against the Department for alleged damages to persons and property and for other alleged liabilities arising out of its operations. In the opinion of management, any ultimate liability, which may arise from these actions, are not expected to materially impact Energy Services' financial position, results of operations or cash flows as of June 30, 2003.

NOTE 15: (continued)

Risk management

Energy Services is subject to certain business risks common to the utility industry. The majority of these risks are mitigated by external insurance coverage obtained by Energy Services. For other significant business risks, however, Energy Services has elected to self-insure. Management believes that exposure to loss arising out of self-insured business risks will not materially impact Energy Services' financial position, results of operations or cash flows as of June 30, 2003.

Credit risk

Financial instruments, which potentially expose the Department to concentrations of credit risk, consist primarily of retail and wholesale receivables. The Department's retail customer base is concentrated among commercial, industrial, residential and governmental customers located within the City. Although the Department is directly affected by the City's economy, management does not believe significant credit risk exists at June 30, 2003, except as provided in the allowance for losses. The Department manages its credit exposure by requiring credit enhancements from certain customers and through procedures designed to identify and monitor credit risk.

NOTE 16: Subsequent Events

On December 17, 2003, the Board approved the reduced sale price of the administrative facility described in Note 14. The reduced price remains subject to City Council approval.

Also on December 17, 2003, the Retirement Board adopted a change in the actuarial asset valuation method for the Department's Retirement, Disability and Death Benefit Insurance Plan from the four-year smoothing method to recognizing the unrecognized returns for each of the last five years (but not before July 11, 2001) over a five-year period.

Water Services
Department of Water and Power
City of Los Angeles

Report and Financial Statements and
Required Supplementary Information

June 30, 2003

Los Angeles Department of Water and Power
Water Services
Financial Statements and Required Supplementary Information - June 30, 2003
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Los Angeles Department of Water and Power
Water Services

Management's Discussion and Analysis
(Unaudited)

June 30, 2003

The following discussion and analysis of the financial performance of the City of Los Angeles' (the City) Department of Water and Power's (the Department), Water System Fund (Water Services), provides an overview of the financial activities for the fiscal year ended June 30, 2003. Descriptions and other details pertaining to Water Services are included in the notes to the financial statements. This discussion and analysis should be read in conjunction with the Water Services' financial statements, which begin on page 17.

Background and Creation of the Department

The Department is the largest municipal utility in the United States and is a separate proprietary agency of the City, controlling its own funds with full responsibility for meeting the electric and water requirements of its service area. The Department provides electric and water service almost entirely within the boundaries of the City, which encompasses some 465 square miles, to a population of approximately 3.9 million people. Certain factors, which affect the water industry, generally apply to the Department's operation of Water Services.

The Department was established under the City Charter adopted in January 1925 as amended effective July 2000. It had its beginning, however, in the early 1900's. The first Board of Water and Power Commissioners was established in 1902. The responsibilities for the provision of water as well as electricity were given to a new Los Angeles Department of Public Service organized in 1911. The Department of Public Service was superceded in 1925 when a new Charter was adopted creating the Department. Subsequently the Water Works and Electric Works came to be known as the Water System (Water Services) and the Power System (Energy Services). The operations and finances of Water Services are separate from those of Energy Services.

Charter Provisions

Governance

Pursuant to the Charter of the City (the Charter), the five-member Board of Water and Power Commissioners (the Board) is the governing body of the Department and the General Manager administers the affairs and operations of the Department. The Board is granted the possession, management, and control of Water Services.

The provisions of the Charter relating to the Department are found in Article VI. Among other things, Article VI provides that all Water Services revenue collected by the Department shall be deposited in the Water Revenue Fund, that the Board shall control the money in the Water Revenue Fund, and makes provisions for the issuance of Department bonds, notes and other evidences of indebtedness payable out of the Water Revenue Fund.

Section 245 of the Charter provides that actions of the Board shall become final at the expiration of the next five meeting days of the City Council (the Council), during which time the Council may bring the matter for review, or veto such action. If the Council votes to bring the matter for review, it has 21 days to conduct its review, otherwise the Board's action on the matter is final.

Rates

Pursuant to the Charter, the Board, subject to the approval of the Council by ordinance, fixes the rates for water service provided by Water Services. The Charter provides that such rates shall be fixed by the Board from time to time as necessary. The Charter also provides that such rates shall, except as authorized by the Charter, be of uniform operation for customers of similar circumstances throughout the City, as near as may be, and shall be fair and reasonable, taking into consideration, among other things, the nature of the uses, the quantity supplied, and the value of the service, and the financial impact on Water Services resulting from such service.

Transfers to the Reserve Fund of the City of Los Angeles

Under the provisions of the Charter, Water Services transfers funds at its discretion to the reserve fund of the City. Pursuant to covenants contained in the bond indentures, the transfers may not be in excess of the increase in fund net assets before transfers to the reserve fund of the City, of the prior fiscal year. Such payments are not in lieu of taxes and are recorded as a reduction of fund net assets in accordance with governmental accounting standards. Water Services made a transfer of 5% of its fiscal 2002 operating revenues, totaling $28 million, to the reserve fund of the City in fiscal 2003. Water Services expects to transfer 5% of its fiscal 2003 operating revenues, or approximately $28 million, to the reserve fund of the City in fiscal 2004.

Critical Accounting Policies

Method of Accounting

The accounting records of Water Services are maintained in accordance with accounting principles generally accepted in the United States of America. As a government-owned utility, in prior years the Department applied all statements issued by the Governmental Accounting Standards Board (GASB) and all statements and interpretations issued by the Financial Accounting Standards Board (FASB), which are not in conflict with statements issued by the GASB. In fiscal year 2003, the Department changed its election under the guidance in GASB Statement No. 20, "*Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities that Use Proprietary Fund Accounting*" (GASBS 20), to follow GASB statements and only FASB statements and interpretations issued on or before November 30, 1989. While the Department is required to retroactively apply this change by restating prior years presented, the change did not have any impact on prior years' financial statements. Therefore, prior periods were not restated. Management believes that this change in election represents a change to a preferable method of accounting. See Note 2 to the financial statements for further information and a description of the impact of the change on prior period results.

Water Services' rates are determined by the Board and are subject to review and approval by the Council. As a regulated enterprise, the Department's financial statements are prepared in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, "*Accounting for the Effects of Certain Types of Regulation,*" which requires that the effects of the ratemaking process be recorded in the financial statements. Such effects primarily concern the time at which various items enter into the determination of changes in fund net assets, in order to follow the principle of matching costs and revenues.

Current Rate Ordinance

A conservation-based water rate ordinance has been in effect since February 16, 1993. The ordinance incorporates marginal cost pricing through a two-tiered rate structure. The upper block rate is established at the estimated marginal cost for water. The lower block price is established to generate the revenue required for efficient operations. As a result of concerns expressed about the rate structure's impact on larger volume single-family residential customers, the first tier allowances were revised effective June 1, 1995. The revisions established five lot size categories and three temperature zones (as the basis for the first tier usage blocks for each category). Extra units (one unit equals 100 cubic feet or 748 gallons) at the first tier rate are available based on household sizes. The rates also reflect equity considerations for water-intensive businesses, large turf customers, and other customers having high seasonal variation in their water usage. Fixed monthly service availability charges apply only to private fire service. The Water System's rate ordinance contains a water

procurement adjustment factor under which the cost of purchased water, including water purchased from the Metropolitan Water District (MWD), demand-side management programs and reclaimed water projects are recovered by direct adjustments to customers' bills. In addition, the ordinance contains a water quality improvement adjustment which recovers expenditures to upgrade and equalize water quality throughout the City and to construct facilities to meet State and federal water quality standards, including the payment of debt service on bonds issued for such purposes. The ordinance currently limits to $0.36 per billing unit the recovery of combined expenditures for demand-side management, water reclamation, and water quality improvement.

The Water System's rate ordinance also contains a revenue adjustment mechanism in the form of a surcharge that is designed to assure a minimum level of base rate revenue each fiscal year based on an annual revenue target of $294 million. The revenue adjustment factor becomes effective upon a determination by the Board that the surcharge is needed. The rate ordinance limits the surcharge to $0.18 per billing unit, unless a higher amount is approved by the Board and the City Council.

Investment Policy and Controls

The Department's cash, other than cash in certain trust funds, is deposited with the City Treasurer, who invests the funds in securities under the City Treasurer's pooled investment program, for the purpose of maximizing interest earnings. Under the program, available funds of the City and its independent operating departments are invested on a combined basis. The primary responsibilities of the City Treasurer are to protect the principal and asset holdings of the City's portfolio and to ensure adequate liquidity to provide for the prompt and efficient handling of City disbursements. The City Treasurer invests these funds in compliance with the applicable California Government Code and the City's Investment Policy. Generally, investments are limited to government securities with credit ratings of AAA and are of varying maturities which can range from less than 90 days to in excess of two years.

Debt Management Program

The debt restructuring element of the Debt Management Program includes the issuance of refunding bonds to achieve debt service savings and to accelerate the maturity of certain bonds while maintaining an appropriate overall annual debt service schedule for all of the Department's obligations in connection with the Water System. The Department has completed the major portion of its refunding program, including the issuance of several series of refunding bonds payable from the Water Revenue Fund under a Master Bond Resolution adopted by the Board on February 6, 2001. Management expects to complete its refunding program within the next fiscal year.

Using This Financial Report

This financial annual report consists of the financial statements and reflects the self-supporting activities of Water Services that are funded primarily through the sale of water to the public it serves.

Balance Sheets, Statements of Revenue, Expenses and Changes in Fund Net Assets, and Statements of Cash Flows

The financial statements provide an indication of Water Services' financial health. The Balance Sheets include all of Water Services' assets and liabilities, using the accrual basis of accounting, as well as an indication about which assets can be utilized for general purposes, and which assets are restricted as a result of bond covenants and other commitments. The Statements of Revenue, Expenses, and Changes in Fund Net Assets report all of the revenues and expenses during the time periods indicated. The Statements of Cash Flows report the cash provided and used by operating activities, as well as other cash sources such as investment income and cash payments for bond principal and capital additions and betterments.

The following table summarizes the financial condition and changes to fund net assets of Water Services as of and for the fiscal years ended June 30, 2003 and 2002 (amounts in millions):

Table 1 - Summary of financial condition and changes in fund net assets

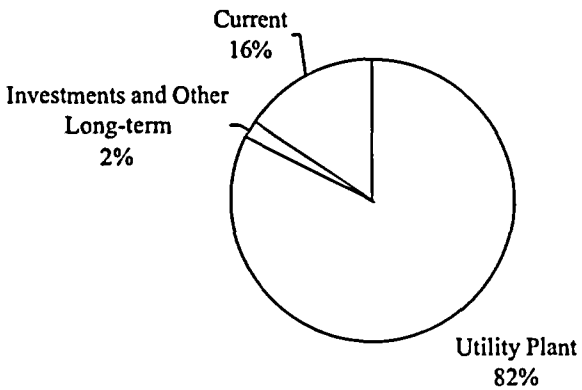
	June 30,	
Assets	**2003**	**2002**
Utility plant, net	$ 2,849	$ 2,695
Restricted investments	5	7
Other long-term assets	58	60
Current assets	538	385
	$ 3,450	$ 3,147
Liabilities and Fund Net Assets		
Long-term debt	$ 1,297	$ 1,000
Other long-term liabilities	110	114
Current liabilities	251	245
	1,658	1,359
Fund net assets:		
Invested in capital assets, net of related debt	1,689	1,701
Restricted fund net assets	108	87
Unrestricted fund net deficit	(5)	-
	1,792	1,788
	$ 3,450	$ 3,147
Revenue, Expenses, and Changes in Fund Net Assets		
Operating revenues	$ 553	$ 551
Operating expenses	(502)	(446)
Operating income	51	105
Investment income	11	9
Other income and expenses, net	13	7
Debt expenses	(43)	(37)
Transfer to the reserve fund of the City of Los Angeles	(28)	(27)
Increase in fund net assets	4	57
Beginning balance of fund net assets	1,788	1,731
Ending balance of fund net assets	$ 1,792	$ 1,788

Assets

Utility Plant

Utility plant is the first category of assets shown on the balance sheet. The utility industry is unique in this regard as most other industries list their long-term assets such as plant and equipment after current assets on the balance sheet. This difference is due to the capital-intensive nature of the utility industry with the most significant portion of that capital being invested in utility plant. As depicted in the chart below, utility plant, net of accumulated depreciation, makes up 82% of the total assets of Water Services as of June 30, 2003.

Chart 1 - Total Assets by Type



During fiscal year 2003, Water Services capitalized $237 million of additions to utility plant in service. Of the $237 million, $111 million, or 47% related to distribution utility plant assets, and $100 million was added to source of supply assets. Additions to distribution utility plant assets comprised the completion of various major reservoir and trunk line projects. Additions to source of supply assets, which included additions to land and land rights, were primarily associated with the completion of Phases I and II of the Owens Valley Dust Mitigation Project. The remaining $31 million of additions were incurred for normal capital activities to maintain and support general plant, pumping and purification systems.

Water Services has budgeted approximately $380 million of capital expenditures for fiscal year 2004.

Water Services utility plant in service assets fall into five major categories: source of water supply, pumping, purification, distribution, and general. Each category of assets is important to providing water services and has a specific purpose. Source of water supply assets are the assets that the Department has constructed and/or purchased to help ensure an adequate supply of water. The Department has four major sources of water. These include:

- Los Angeles Aqueduct and Second Los Angeles Aqueduct supply imported water from the Owens Valley and the Mono Basin;
- Local groundwater supply (with pumping rights in the San Fernando, Sylmar, Central and West Coast Basins);
- Purchased supply from MWD;
- Recycled water.

All sources of water, except for recycled water, are supplied for potable use; that is, the water from these sources is of drinkable quality. Table 2 below shows the percentage of potable water delivered from the major sources.

Table 2 - Sources of Potable Water Supplied During Fiscal Year 2003

Source	Millions of Gallons	Percent
Aqueduct	66,417	31%
Wells	29,555	14%
Purchases	121,297	55%
	217,269	100%

Water storage during low demand, cold, or wet periods is essential for conservation, to supply the extra water needed during warm weather or emergency situations.

The Water System's 101 tanks and reservoirs, ranging in size from 10 thousand to 60 billion gallons, have a current capacity of approximately 339,261 acre-feet, or 110.54 billion gallons. Eight aqueduct reservoirs provide 92% of the Water System's storage capacity; major and minor distribution reservoirs provide the remaining 8%.

Under-recovered costs

Under-recovered costs is a current asset on Water Services' balance sheet. Under-recovered costs are the costs that Water Services has incurred for water supply and other designated costs in excess of amounts billed to the customer. Expenses that are recovered through this rate include purchased water expense, water quality expense, reclaimed water expense, and demand-side management (or conservation expense). Under-recovered costs decreased by $1 million from June 30, 2002 to June 30, 2003, due to a reduction in reclaimed water expenditures.

Due from Energy Services

As of June 30, 2003, Water Services was owed $67 million from Energy Services, an increase of $61 million over June 30, 2002. Amounts owed between the two funds are generally settled within one month. The increase as of June 30, 2003 is due to a short term suspension of payments to Water Services by Energy Services of amounts owing for cash management purposes and represents three months of amounts outstanding. The additional months outstanding were repaid to Water Services as of September 2003.

Investments

The Department sets aside funds to be used in future years for specified purposes. At June 30, 2003, $5 million in restricted and other investments was held by Water Services, consisting of U.S. government securities. These investments are set aside for the purpose of paying interest on previously issued refunding debt. In addition, Water Services share of the Department's postretirement health care benefit trust fund, established to provide for the payment of the Department's postretirement health care benefits, totaled $53 million as of June 30, 2003. These investments have been recorded as a reduction to Water Services' postretirement liability.

The Department has a securities lending program which, for Water Services, allows it to lend up to 20% of its investments held in the postretirement benefits trust fund for securities, cash collateral or letters of credit equal to 102% of the market value of the loaned securities and interest, if any. The lending agent provides indemnification for borrower default. There were no violations of legal or contractual provisions and no borrower or lending agent default losses during fiscal years 2003 and 2002.

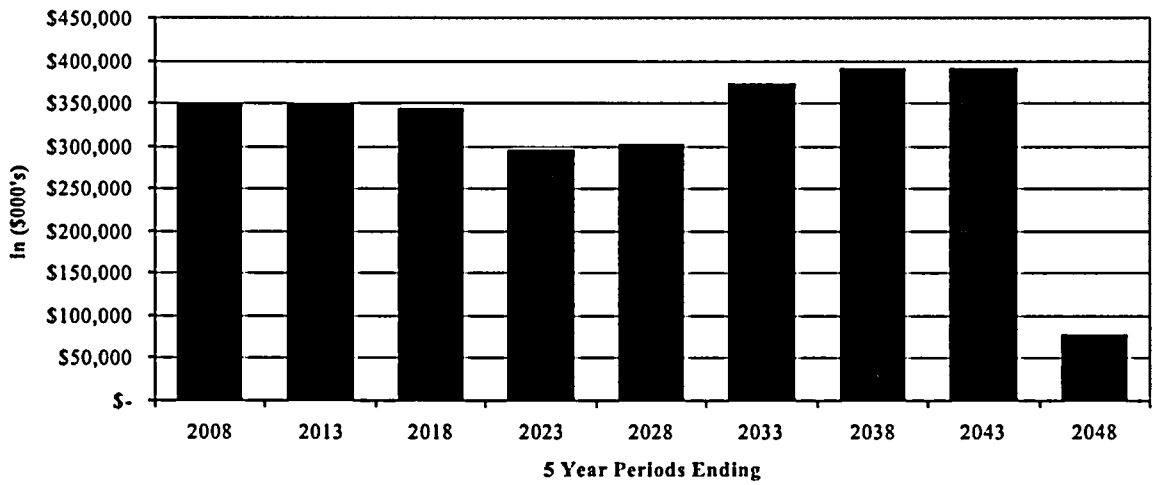
In addition, Water Services participates in the City's securities lending program and is allocated its share of the collateral received and the related liability, as well as earnings from the program. As of June 30, 2003 and 2002, the amount of collateral and liability pertaining to securities lending programs was $40 million and $34 million, respectively. Management believes that participation in these securities lending programs results in no credit risk exposure to the Department because the amounts owed to the borrowers exceed the amounts the borrowers owe to the Pool.

Liabilities and Fund Net Assets

Long-term debt

As of June 30, 2003, Water Services' total long-term debt balance was $1.3 billion. This is an increase of $299 million over the prior year, reflecting primarily the issuance of $502 million in revenue bonds during the year, offset by the current refunding of $197 million, maturities of $3 million and net amortization of debt discounts and premiums of $3 million. Outstanding principal, plus scheduled interest and amortization as of June 30, 2003, is scheduled to mature as shown in the chart below:

Chart 2: Debt Service Requirements



As of June 30, 2003, $194 million principal amount of long-term debt is considered defeased and remains outstanding. This debt, together with trust funds set aside for its full repayment at scheduled maturity dates, has been derecognized and is not reflected on the balance sheet.

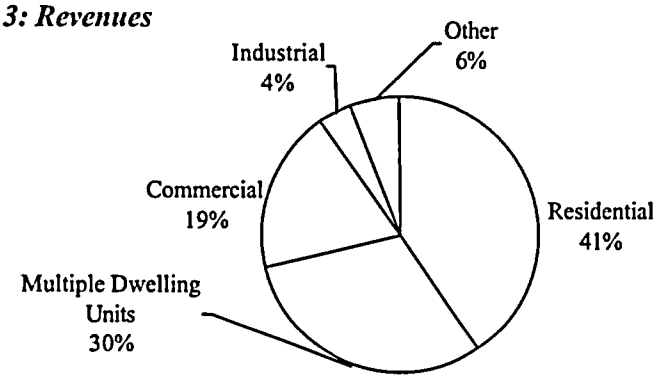
Changes in Fund Net Assets

Revenues

The operating revenues of Water Services are generated from selling water to its customers. The current water rate has two components, a base rate, and an adjustable rate, which is referred to as a pass through rate. The pass through rate is in place to recover the cost of specific expenses. These expenses include purchased water, water quality, reclaimed water, and demand-side management (or conservation expense). This is important to understand from a revenue standpoint because revenue can increase or decrease from one year to the next based on Water Services incurring greater or lesser expenses in these categories.

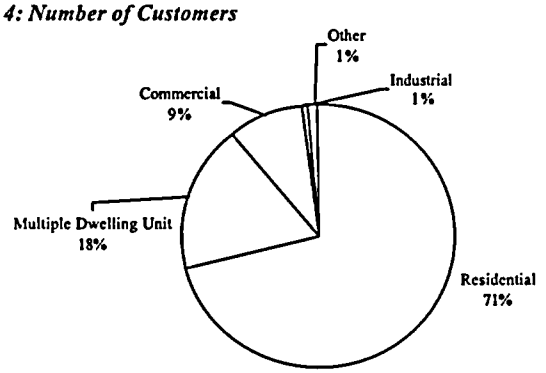
Water Services has five major customer categories. These categories include residential, multiple dwelling units, commercial, industrial, and other. Chart 3 summarizes the percentage contribution of revenues from each customer category during fiscal year 2003:

Chart 3: Revenues



Residential customers provide 41% of the revenue and they are Water Services' largest class of customers. As of June 30, 2003, Water Services had approximately 659 thousand customers. As shown in Chart 4, 469 thousand, or 71% of total customers, were in the residential customer class as of June 30, 2003.

Chart 4: Number of Customers



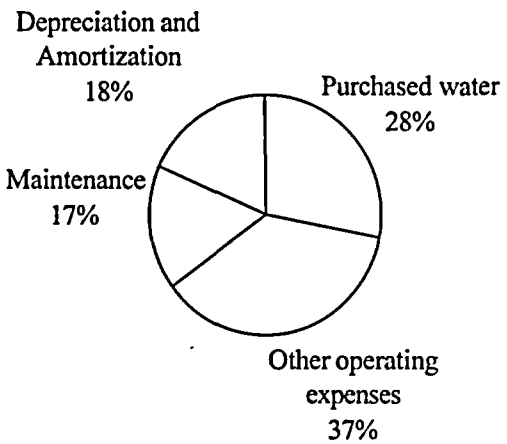
During fiscal year 2003, operating revenues increased by $3 million, or 0.5% from fiscal year 2002 levels due to an increase in pass-through recoverable costs. Due to additional qualifying pass-through recoverable costs, the average rate was higher in fiscal year 2003. The additional revenue from pass-through rates was partially offset by a minor decrease in consumption for all customer classes due to cooler and wetter weather.

During fiscal year 2002, operating revenues increased by $9 million, or 2% from fiscal year 2001 levels due to an increase in pass-through recoverable costs and higher consumption due to a sharp decrease in precipitation from fiscal year 2001.

Operating Expenses

Purchased water expense is the single largest expense that Water Services incurs each fiscal year. Purchased water expense represents the cost of buying water, primarily from the Metropolitan Water District (MWD). For fiscal year 2003, 55% of the potable water supplied to Water Services' customers was purchased water. Chart 5 summarizes Water Services' operating expenses for fiscal year 2003:

Chart 5: Operating Expenses



Fiscal year 2003

Fiscal year 2003 operating expenses were $56 million higher as compared to the prior year. This increase was due to an increase in purchased water costs of $6 million, an increase in other operating and maintenance expenses of $46 million, and an increase of $4 million in depreciation and amortization expense.

Other operating and maintenance expenses increased primarily as a result of continued increases in environmental costs associated with ongoing operations and maintenance phases of Owens Valley remediation, increased retirement, death and disability expenses and health care costs as a result of higher benefit and medical costs.

Purchased water costs have increased $6 million over fiscal year 2002. In fiscal year 2002, Water Services received a revenue rebate credit from MWD of approximately $6 million. The Department did not receive such a credit in fiscal year 2003 and otherwise experienced similar expense levels due to higher quantities purchased offset by lower average unit prices.

The increase in depreciation and amortization expense is associated with utility plant additions.

Fiscal year 2002

Fiscal year 2002 operating expenses were $40 million higher as compared to fiscal year 2001. This increase was mostly due to an increase in other operating and maintenance expenses of $33 million, and an increase of $7 million in depreciation and amortization expense.

Other operating and maintenance expenses increased primarily as a result of increased security costs associated with increasing patrols and surveillance of the Department's water systems and sources. In addition, Water Services experienced an increase in environmental costs associated with Owens Valley and legal costs.

The increase in depreciation and amortization expense was associated with utility plant additions.

Non-Operating Revenue and Expenses

Fiscal year 2003

The major non-operating activities of Water Services for fiscal year 2003 include the transfer of $28 million to the reserve fund of the City of Los Angeles; interest income earned on cash and investments of $11 million, $43 million in debt expenses, net of allowance for funds used during construction, and earned contributions in aid of construction of $14 million. Furthermore, Water Services recognized a $3 million impairment charge during fiscal year 2003 relating to the sale of one of its administrative facilities. The Department entered into a sale transaction for the facility and reduced the sale price as a result of mold that was discovered in the facility. See Note 10 of the financial statements for further discussion.

Interest on investments followed the general trend in interest rates and declined from an average yield of 4.28% in fiscal year 2002 to 3.48% in fiscal year 2003. Interest on debt service increased due to additional debt of $300 million being issued during fiscal 2003.

Fiscal year 2002

The major non-operating activities of Water Services for fiscal year 2002 include the abandonment of various construction projects totaling $16 million; the transfer of $27 million to the reserve fund of the City of Los Angeles; interest income earned on our investments of $9 million, $37 million in interest expenses, and contributions in aid of construction of $17 million.

Interest on investments followed the general trend in interest rates and declined from an average yield of 5.28% in fiscal year 2001 to 4.28% in fiscal year 2002. Interest on debt service declined due to lower rates on variable rate debt and the effects of the debt restructuring program, which lowered average interest rates on fixed rate debt.

Risk Factors

Water Services' primary business is to provide its customers with safe and reliable water service. Water Services manages its overall cost of providing service by monitoring its water supply and demand data. In addition, Water Services purchases water for customers when the Department's supply is maximized.

The Department has traditionally acquired the majority of its water from the Los Angeles Aqueduct, the Second Los Angeles Aqueduct, local wells, and purchases from MWD. The Department believes that proper management of these sources, coupled with water recycling and conservation programs, will provide adequate water supplies to meet the needs of the City for the foreseeable future. Rules and regulations surrounding water quality and the environment continue to become more stringent. As such, the Department continually monitors its compliance requirements. Water Services may incur additional capital expenditures in order to meet the rules and regulations. Requirements currently in place that affect Water Services include the Surface Water Treatment Rule and environmental remediation relating to Owens Valley. Based on current significant requirements in effect, Water Services expects that it will incur a total of approximately $954 million to meet these requirements through 2007.

With respect to water supply, the Department is working at protecting the reliability of existing supplies and sources. It is the Department's intent to ensure the reliability of imported water. The Department has adopted a goal of meeting as much of the additional water demands arising from growth over the next 20 years through water conservation and reclamation programs as possible. Any additional supply will be obtained through purchases from MWD. However, the Department cannot guarantee that these programs or other measures will provide the additional supply requirements of the City.

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Report of Independent Auditors

To the Board of Water and Power Commissioners
Department of Water and Power
City of Los Angeles

In our opinion, the accompanying balance sheets and the related statements of revenue, expenses and changes in fund net assets and of cash flows present fairly, in all material respects, the financial position of the Water System (Water Services) of the Department of Water and Power of the City of Los Angeles at June 30, 2003 and 2002, and the changes in its fund net assets and its cash flows for each of the three years in the period ended June 30, 2003 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Department's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 2 to the financial statements, effective July 1, 2002, Water Services changed its election under Governmental Accounting Standards Board Statement No. 20, "*Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities that Use Proprietary Fund Accounting,*" and no longer applies Financial Accounting Standards Board statements and interpretations issued after November 30, 1989.

The management's discussion and analysis included on pages 1 through 15 is not a required part of the basic financial statements but is supplementary information required by the Governmental Accounting Standards Board. We have applied certain limited procedures, which consisted primarily of inquiries of management regarding the methods of measurement and presentation of the required supplementary information. However, we did not audit the information and express no opinion on it.

PricewaterhouseCoopers LLP

November 26, 2003, except for Note 12, which is as of December 17, 2003

Los Angeles Department of Water and Power
Water Services Balance Sheets
(Amounts in thousands)

	June 30,	
	2003	2002
Assets		
Non-Current Assets		
Utility Plant		
Source of water supply	$ 584,317	$ 462,420
Pumping	190,074	190,207
Purification	239,979	241,774
Distribution	2,612,116	2,526,522
General	345,655	327,559
	3,972,141	3,748,482
Accumulated depreciation	1,385,526	1,328,057
	2,586,615	2,420,425
Construction work in progress	262,252	274,433
	2,848,867	2,694,858
Restricted investments	4,613	7,586
Net pension asset	58,552	59,848
	63,165	67,434
Current Assets		
Cash and cash equivalents - unrestricted	45,078	103,305
Cash and cash equivalents - restricted	231,767	75,355
Cash collateral received from securities lending transactions	40,071	33,781
Customer and other accounts receivable, net of $3,500 allowance for losses	62,467	73,458
Underrecovered costs	23,075	24,169
Due from Energy Services	67,447	6,024
Accrued unbilled revenue	44,214	41,287
Materials and supplies	15,027	17,752
Prepayments and other current assets	9,482	9,685
	538,628	384,816
	$ 3,450,660	$ 3,147,108

The accompanying notes are an integral part of these financial statements

Los Angeles Department of Water and Power
Water Services Balance Sheets
(Amounts in thousands)

	June 30,	
	2003	2002
Fund Net Assets and Liabilities		
Fund Net Assets		
Invested in capital assets, net of related debt	$ 1,688,726	$ 1,701,161
Restricted fund net assets	108,089	87,053
Unrestricted fund net deficit	(4,708)	(605)
	1,792,107	1,787,609
Long term debt	1,297,190	1,000,414
Other Non-Current Liabilities		
Accrued postretirement liability	99,186	105,391
Accrued workers' compensation claims	10,969	8,700
Commitments and contingencies (Note 11)	-	-
	110,155	114,091
Current Liabilities		
Current portion of long-term debt	47,632	45,137
Accounts payable and accrued expenses	67,960	86,346
Accrued interest	20,214	9,247
Accrued employee expenses	33,010	26,001
Obligation under securities lending transactions	40,071	33,781
Customer deposits	42,321	44,482
	251,208	244,994
	$ 3,450,660	$ 3,147,108

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

Los Angeles Department of Water and Power
Water Services Statements of Revenue, Expenses, and Changes in Fund Net Assets
(Amounts in thousands)

	Year Ended June 30,		
	2003	2002	2001
Operating Revenues			
Residential	$ 227,265	$ 225,611	$ 217,029
Multiple dwelling units	169,760	169,279	167,309
Commercial and industrial	129,111	125,716	126,927
Other	32,689	35,343	33,675
Uncollectible accounts	(5,848)	(5,480)	(3,947)
	552,977	550,469	540,993
Operating Expenses			
Purchased water	141,389	135,049	134,480
Maintenance and other operating expenses	269,510	223,341	190,083
Depreciation and amortization	91,520	87,493	80,910
	502,419	445,883	405,473
Operating Income	50,558	104,586	135,520
Other Income and Expense			
Investment income	11,490	9,075	27,350
Gain on sale of land	2,270	4,896	462
Other non-operating income	5,156	5,918	5,432
	18,916	19,889	33,244
Other non-operating expenses	4,618	4,709	4,609
	14,298	15,180	28,635
Loss on asset impairment and abandoned projects	(3,402)	(15,550)	(35,601)
	10,896	(370)	(6,966)
Debt Expenses			
Interest on debt	46,464	40,223	46,234
Allowance for funds used during construction	(2,987)	(3,409)	(2,023)
	43,477	36,814	44,211
Contributions in aid of construction	14,044	16,757	19,790
Change in fund net assets before transfers to the reserve fund of the City of Los Angeles and extraordinary item	32,021	84,159	104,133
Transfers to the reserve fund of the City of Los Angeles	27,523	27,247	25,500
Increase in fund net assets before extraordinary item	4,498	56,912	78,633
Extraordinary loss on extinguishment of debt	-	-	(3,096)
Increase in fund net assets	4,498	56,912	75,537
Fund net assets			
Beginning of period	1,787,609	1,730,697	1,655,160
End of period	$ 1,792,107	$ 1,787,609	$ 1,730,697

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

Los Angeles Department of Water and Power
Water Services Statements of Cash Flows
(Amounts in thousands)

	Year Ended June 30,		
	2003	2002	2001
Cash Flows from Operating Activities:			
Cash Receipts			
Cash receipts from customers	$ 593,625	$ 599,034	$ 544,729
Cash receipts from customers for other agency services	360,886	360,216	356,004
Cash receipts from interfund services provided	235,412	238,918	227,218
Other operating cash receipts	-	6,761	33,163
Cash Disbursements			
Cash payments to employees	(179,611)	(176,869)	(159,916)
Cash payments to suppliers	(298,676)	(229,037)	(277,672)
Cash payments for interfund services used	(238,347)	(201,228)	(175,907)
Cash payments to other agencies for fees collected	(359,274)	(355,254)	(357,459)
Other operating cash payments	(1,175)	-	-
	112,840	242,541	190,160
Cash Flows from Noncapital Financing Activities:			
Payments to the reserve fund of the City of Los Angeles	(27,523)	(27,247)	(25,500)
Cash Flows from Capital and Related Financing Activities:			
Additions to plant and equipment, net	(245,944)	(339,833)	(254,448)
Contributions in aid of construction	16,936	24,043	18,819
Purchases of escrow investments	-	-	(103,927)
Proceeds from escrow investment maturities	3,085	96,648	307,632
Principal payments and maturities on long-term debt, net	(2,565)	(10,185)	(86,665)
Issuance of bonds, net	489,773	3,004	730,482
Payment for refunded revenue bonds	(197,310)	(94,800)	(559,616)
Proceeds from California Department of Water Resources loan	-	13,253	-
Debt interest payments	(30,049)	(48,670)	(56,745)
	33,926	(356,540)	(4,468)
Cash Flows from Investing Activities:			
Purchases of investment securities	(32,640)	-	-
Investment income	11,582	19,503	33,335
	(21,058)	19,503	33,335
Cash and Cash Equivalents:			
Net increase (decrease)	98,185	(121,743)	193,527
Beginning of year	178,660	300,403	106,876
End of year	$ 276,845	$ 178,660	$ 300,403

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

Los Angeles Department of Water and Power
Water Services Statements of Cash Flows, continued
(Amounts in thousands)

	Year Ended June 30,		
	2003	2002	2001
Reconciliation of operating income to net cash provided by operating activities			
Operating income	$ 50,558	$ 104,586	$ 135,520
Adjustments to reconcile operating income to net cash provided by operating activities			
Depreciation and amortization	91,520	87,493	80,910
Provision for losses on customer and other accounts receivable	5,848	5,480	3,947
Changes in assets and liabilities:			
Customer and other accounts receivable	5,264	(10,331)	(12,284)
Due from Energy Services	(61,423)	1,316	(5,996)
Materials and supplies	2,725	(81)	(1,918)
Net pension asset	1,296	(7,026)	(7,309)
Accounts payable and accrued expenses	(18,386)	9,836	4,260
Accrued employee expenses	7,009	2,145	3,694
Under-/Over-recovered costs	1,094	(4,682)	(19,670)
Accrued postretirement liability	26,435	22,501	13,703
Workers' compensation liability and other	900	31,304	(4,697)
Cash provided by operating and other activities	$ 112,840	$ 242,541	$ 190,160
Non-cash capital and related financing activities:			
Loss on asset impairment and abandoned projects	$ (3,402)	$ (15,550)	$ (35,601)
Extraordinary loss on extinguishment of debt	$ -	$ -	$ (3,096)

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

NOTE 1: Summary of Significant Accounting Policies

The Department of Water and Power of the City of Los Angeles (the Department) exists as a separate proprietary agency of the City of Los Angeles (the City) under and by virtue of the City Charter enacted in 1925 and as revised effective July 2000. The Department's Water System (Water Services) is responsible for the procurement, quality, and distribution of water for sale in the City.

Method of accounting

The accounting records of Water Services are maintained in accordance with accounting principles generally accepted in the United States of America. As a government-owned utility, in prior years, the Department applied all statements issued by the Governmental Accounting Standards Board (GASB) and all statements and interpretations issued by the Financial Accounting Standards Board (FASB), which are not in conflict with statements issued by the GASB. In fiscal year 2003, the Department changed its election under the guidance in GASB Statement No. 20, "*Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities that Use Proprietary Fund Accounting*" (GASBS 20), to follow GASB statements and only FASB statements and interpretations issued on or before November 30, 1989. See Note 2.

The Department's rates are determined by the Board of Water and Power Commissioners (the Board) and are subject to review and approval by the City Council. As a regulated enterprise, the Department utilizes Statement of Financial Accounting Standards (SFAS) No. 71, "*Accounting for the Effects of Certain Types of Regulation,*" which requires that the effects of the ratemaking process be recorded in the financial statements. Such effects primarily concern the time at which various items enter into the determination of changes in fund net assets. Accordingly, Water Services records various regulatory assets and liabilities to reflect the Board's actions. Management believes that Water Services meets the criteria for continued application of SFAS No. 71, but will continue to evaluate its applicability based on changes in the regulatory and competitive environment.

Use of estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

NOTE 1: (continued)

Utility plant

The costs of additions to utility plant and replacements of retired units of property are capitalized. Costs include labor, materials, an allowance for funds used during construction (AFUDC), and allocated indirect charges such as engineering, supervision, transportation and construction equipment, retirement plan contributions, health care costs, and certain administrative and general expenses. The costs of maintenance, repairs and minor replacements are charged to the appropriate operations and maintenance expense accounts. The original cost of property retired, net of removal and salvage costs, is charged to accumulated depreciation.

Impairment of long-lived assets

Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be fully recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of the assets to their fair value, which is normally determined through analysis of the future undiscounted net cash flows expected to be generated by the assets. If such assets are considered to be impaired, the impairment to be recognized at that time is measured by the amount that the carrying amount of the assets exceeds the fair value of the assets.

Depreciation and amortization

Depreciation expense is computed using the straight-line method based on service lives. The Department uses the composite method of depreciation and therefore groups assets into composite groups for purposes of calculating depreciation expense. Estimated service lives range from 5 to 70 years. Amortization expense for computer software is computed using the straight-line method over 5 years. Depreciation and amortization expense as a percentage of average depreciable utility plant in service was 2.6% for each of the fiscal years ended 2003, 2002 and 2001, respectively.

NOTE 1: (continued)

Cash and cash equivalents

As provided for by the California Government Code, the Department's cash is deposited with the City Treasurer in the City's general investment pool for the purpose of maximizing interest earnings through pooled investment activities. Cash and cash equivalents in the City's general investment pool are reported at fair value and changes in unrealized gains and losses are recorded in the statements of revenue, expenses, and changes in fund net assets. Interest earned on such pooled investments is allocated to the participating funds based on each fund's average daily cash balance during the allocation period. The City Treasurer invests available funds of the City and its independent operating departments on a combined basis. The Department classifies all cash and cash equivalents that are restricted either by creditors, the Board, or by law, as restricted cash and cash equivalents on the balance sheet. The Department considers its portion of pooled investments with an original maturity of three months or less to be cash equivalents.

At June 30, 2003 and 2002, restricted cash and cash equivalents includes the following (amounts in thousands):

	June 30,	
	2003	2002
Bond redemption and interest funds	$ 36,921	$ 14,086
Construction funds	184,681	51,854
Self insurance fund	10,165	9,415
	$ 231,767	$ 75,355

Materials and supplies

Materials and supplies are recorded at average cost.

Restricted investments

Water Services' restricted investments consist of escrow investments held to pay interest on previously issued refunding revenue bonds. Such investments include U.S. government and governmental agency securities. Investments are reported at fair value and changes in unrealized gains and losses are recorded in the statement of revenue, expenses, and changes in fund net assets. Gains and losses realized on the sale of investments are generally determined using the specific identification method. The stated fair value of investments is generally based on published market prices or quotations from major investment dealers.

NOTE 1: (continued)

Accrued employee expenses

Accrued employee expenses includes accrued payroll and an estimated liability for vacation leave, sick leave and compensatory time, which is accrued when employees earn the rights to the benefits.

Debt expenses

Debt premium, discount, and issue expenses are deferred and amortized to debt expense using the effective interest method over the lives of the related debt issues. Gains and losses on refundings related to bonds redeemed by proceeds from the issuance of new bonds are amortized to debt expense using the effective interest method over the shorter of the life of the new bonds or the remaining term of the bonds refunded. Gains and losses on bond defeasances financed with cash are reported as an extraordinary gain or loss on extinguishment of debt in the statements of revenue, expenses, and changes in fund net assets.

Accrued workers' compensation claims

Liabilities for unpaid workers' compensation claims are recorded at their net present value when they are probable of occurrence and the amount can be reasonably estimated. The liability is actuarially determined, based on an estimate of the present value of the claims outstanding and an amount for claim-events incurred but not reported based upon the Department's loss experience, less the amount of claims and settlements paid to date. The discount rate used to calculate this liability at its present value was 4% at June 30, 2003, which approximates the Department's long term investment yield.

Overall indicated reserves for workers' compensation claims, for both Water and Energy Services, undiscounted, have increased from $40.9 million as of June 30, 2002, to $45.5 million as of June 30, 2003. This increase is mainly attributable to increased medical inflation (particularly in the area of prescription drugs), significant increases in benefit levels implemented in California in the past few years, increased payroll levels of the Department contributing to higher indemnity losses, and increasing claim frequencies experienced by the Department in the past few years. The undiscounted reserves of $45.5 million are net of $43.2 million of cumulative payments made for claims by the Department as of June 30, 2003, for all outstanding policy years. As the claims typically take longer than 1 year to settle and close out, the entire discounted liability is shown as long term on the balance sheets as of June 30, 2003 and 2002. Water Services' portion of the undiscounted reserves as of June 30, 2003 was $16.8 million.

NOTE 1: (continued)

Customer deposits

Customer deposits represent deposits collected from customers upon opening of new accounts. These deposits are obtained when the customer does not have a previously established credit history with the Department. Original deposits plus interest is paid to the customer once a satisfactory payment history is maintained, generally after one to three years. Interest is accrued by Water Services at the prevailing rate established by the Department, which historically has been approximately 3.5%.

Water Services is responsible for collection, maintenance and refunding of these deposits for all Department customers, including those of Energy Services. As such, the deposit liability of $42.3 and $44.5 million on Water Services' balance sheet as of June 30, 2003 and 2002, respectively, is inclusive of amounts due to both Water Services and Energy Services customers. In the event that Water Services defaults on refunds of such deposits, Energy Services would be required to pay amounts owing to its customers.

Revenues

Water Services' rates are established by a rate ordinance, which is approved by the City Council. Water Services sells water to other City departments at rates provided in the ordinance. Water Services recognizes water costs in the period incurred and accrues for estimated water sold but not yet billed.

Revenues consist of billings to customers for water consumption at rates specified in the water rate ordinance. These rates include a cost adjustment factor that provides Water Services with full recovery of purchased water costs. Water Services is also authorized to collect approved demand-side management, water reclamation, and water quality improvement expenditures. Management estimates these costs to establish the cost recovery component of customer billings and any difference between billed and actual costs is adjusted in subsequent billings. This difference is reflected as under- or over-recovered costs on the balance sheet.

The rate ordinance limits Water Services' recovery of combined expenditures for demand-side management, water reclamation, and water quality improvement. During fiscal year 2003 and 2002, Water Services incurred expenditures of $33 million and $24 million, respectively, in excess of these limits, which is being funded through funds received from the issuance of debt (see Note 6). These expenditures were not recovered during fiscal year 2003 or 2002; however, Water Services' rate ordinance permits future recovery of principal and interest payments related to debt used to fund approved expenditures over the life of the related debt issues.

During fiscal year 2002, Water Services changed its under-recovered cost estimate for certain customers. This change resulted in a $12 million increase to under-recovered costs at June 30, 2002.

NOTE 1: (continued)

Non-operating revenues

Contributions in aid of construction and other grants received by the Department for constructing utility plant and other activities are recognized as non-operating revenues when all applicable eligibility requirements, including time requirements, are met.

Allowance for funds used during construction

Allowance for funds used during construction represents the cost of borrowed funds used for the construction of utility plant. Capitalized AFUDC is included as part of the cost of utility plant and as a reduction of debt expenses. The average AFUDC rate used by Water Services was 4.6%, 5.8%, and 5.8% for each of fiscal years 2003, 2002 and 2001.

Reclassifications

Certain financial statement items for prior years have been reclassified to conform to the current year presentation.

Recent Accounting Pronouncements

In May 2002, the GASB issued GASBS No. 39, "*Determining Whether Certain Organizations Are Component Units.*" This Statement amends GASB Statement No. 14, "*The Financial Reporting Entity,*" to provide additional guidance to determine whether certain organizations for which the primary government is not financially accountable should be reported as component units, based on the nature and significance of their relationship with the primary government. Generally, it requires reporting, as a component unit, an organization that raises and holds economic resources for the direct benefit of a governmental unit. This Statement is effective for the Department beginning in fiscal year 2004. The Department does not expect that there will be a material impact to financial statements as a result of adopting this Statement.

In November 2003, the GASB issued GASBS No. 42 "*Accounting and Financial Reporting for Impairment of Capital Assets and for Insurance Recoveries.*" This Statement establishes accounting and financial reporting standards for impairment of capital assets. A capital asset is considered impaired when its service utility has declined significantly and unexpectedly. This Statement also clarifies and establishes accounting requirements for insurance recoveries. Under the standard, impaired capital assets that will no longer be used by the government should be reported at the lower of carrying value or fair value. Impairment losses on capital assets that will continue to be used by the government should be measured using the method that best reflects the diminished service utility of the capital asset. This Statement is effective for the Department beginning in fiscal year 2005 and will not require restatement of previously reported impairment charges. The Department has not yet determined the financial statement impact of adopting the new Statement.

NOTE 2: Accounting Changes

Change in election under GASB Statement No. 20

In fiscal year 2003, the Department changed its election under the guidance in GASB Statement No. 20, "*Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities that Use Proprietary Fund Accounting*" (GASBS No. 20), to follow GASB statements and only FASB statements and interpretations issued on or before November 30, 1989. While the Department is required to retroactively apply this change by restating prior years presented, the change did not have any impact on prior years' financial statements. Therefore, prior periods were not restated. Management believes that this change in election represents a change to a preferable method of accounting.

The Department has continued to apply the provisions of SFAS No. 106, "*Employers' Accounting for Postretirement Benefits Other Than Pensions,*" and recognizes expense associated with postretirement benefits other than pensions on an accrual basis. Currently, there is no prescriptive guidance under governmental standards, however the GASB is finalizing its project on accounting for postretirement benefits other than pensions. The Department will continue to apply the provisions of SFAS No. 106 until the GASB has finalized its project, and will adopt the new GASB Standard as required in the final transition guidance. See Note 8.

GASB Statements Nos. 34, 37 and 38

On July 1, 2001, the Department adopted GASB Statement No. 34 (GASBS 34), "*Basic Financial Statements and Management's Discussion and Analysis for State and Local Governments,*" GASB Statement No. 37 (GASBS 37), "*Basic Financial Statements and Management's Discussion and Analysis for State and Local Governments: Omnibus – an Amendment of GASB Statements No. 21 and No. 34*" and GASB Statement No. 38 "*Certain Financial Statement Note Disclosures*" (GASBS 38). GASBS 34, as amended, and GASBS 38 establish specific standards for external financial reporting for all state and local governments. As a result of adopting these Standards, the basic financial statement presentation was significantly changed, including adding management's discussion and analysis of operating, investing and financing activities. GASBS 34 also requires the classification of fund net assets into three components – invested in capital assets, net of related debt; restricted; and unrestricted. These classifications are defined as follows:

- Invested in capital assets, net of related debt – This component of net assets consists of capital assets, net of accumulated depreciation reduced by the outstanding debt balances, net of unamortized debt expenses and unspent debt proceeds.

NOTE 2: (continued)

- Restricted – This component consists of net assets with constraints placed on their use, either externally or internally. Constraints include those imposed by creditors (such as through debt covenants), grants or laws and regulations of other governments, or by law through constitutional provisions or enabling legislation or by the Board.

- Unrestricted – This component of net assets consists of net assets that do not meet the definition of "restricted" or "invested in capital assets, net of related debt."

Under GASBS 34, the statement of income was renamed the statement of revenue, expenses, and changes in fund net assets, and the statement of cash flows is required to be presented using the direct method (including a reconciliation of operating cash flows to operating income). Under GASBS 34, uncollectible debt expense was reclassified as a reduction of operating revenues.

In fiscal 2002, the Department restated its prior year financial statements to retroactively apply GASBS 34, as amended.

NOTE 3: Utility Plant

Water Services had the following activity in utility plant during fiscal year 2003 (amounts in thousands):

	Balance June 30, 2002	Additions	Retirements and Disposals	Transfers	Reclassifications	Balance June 30, 2003
Nondepreciable utility plant						
Land and land rights	$ 65,156	$ -	$ (5)	$ 27,230	$ -	$ 92,381
Construction work in progress	274,433	155,322	-	(167,503)	-	262,252
Total nondepreciable utility plant	339,589	155,322	(5)	(140,273)	-	354,633
Depreciable utility plant						
Source of water supply	416,645	22,488	(404)	72,578	-	511,307
Pumping	188,108	2,263	(4,164)	1,768	-	187,975
Purification	241,765	1,607	(149)	2,504	(5,757)	239,970
Distribution	2,512,110	47,614	(31,209)	63,423	5,757	2,597,695
General	324,698	22,687	(4,572)	-	-	342,813
Total depreciable utility plant	3,683,326	96,659	(40,498)	140,273	-	3,879,760
Less accumulated depreciation*	(1,328,057)	(97,747)	40,278	-	-	(1,385,526)
Total utility plant, net	$ 2,694,858	$ 154,234	$ (225)	$ -	$ -	$ 2,848,867

* *Additions to accumulated depreciation include capitalized depreciation of $9.3 million.*

NOTE 4: Restricted Investments

A summary of Water Services' restricted investments is as follows (amounts in thousands):

	June 30,	
	2003	2002
Restricted Investments:		
Escrow investments	$ 4,613	$ 7,586
Other:		
Cash collateral received from securities lending transactions (see Note 5)	$ 40,071	$ 33,781
Postretirement health care benefit trust fund	53,478	18,766
Total	$ 98,162	$ 60,133

All restricted and other investments are held in trust accounts to be used for a designated purpose as follows:

Escrow investments

Escrow investments are held to pay interest on previously issued refunding revenue bonds.

Postretirement health care benefit trust fund

The postretirement health care benefit trust fund was established to provide for the payment of the Department's postretirement health care benefits. Accrued postretirement liabilities are recorded net of the trust fund (see Note 8).

Restricted and other investments held by the Department are categorized separately below to give an indication of the level of custodial credit risk assumed by the Department. Specifically, identifiable investments are classified as to credit risk by three categories and summarized below as follows: Category 1 includes investments that are insured or registered or for which securities are held by the Department or its agent in the Department's name; Category 2 includes uninsured and unregistered investments for which the securities are held by the counterparty's trust department or agent in the Department's name; and Category 3 includes uninsured and unregistered investments for which the securities are held by the counterparty or by its trust department or agent, but not in the Department's name.

NOTE 4: (continued)

At June 30, 2003, Water Services' restricted and other investments are categorized as follows (amounts in thousands):

Type of Investments	Category 1	Category 2	Category 3	Total
Investments - categorized				
U.S. government securities	$ 50,223	$ -	$ -	$ 50,223
Bonds	7,815	-	-	7,815
Commercial paper	20	-	-	20
Total categorized restricted and other investments	$ 58,058	$ -	$ -	58,058
Investments - not categorized				
Investments held by broker-dealers:				
Mutual funds				33
General pooled securities lending cash collateral				40,071
Total				$ 98,162

At June 30, 2002, Water Services' restricted and other investments were categorized as follows (amounts in thousands):

Type of Investments	Category 1	Category 2	Category 3	Total
Investments - categorized				
U.S. government securities	$ 15,857	$ -	$ -	$ 15,857
Bonds	3,927	-	-	3,927
Repurchase agreements	-	6,691	-	6,691
Total categorized restricted and other investments	$ 19,784	$ 6,691	$ -	26,475
Investments - not categorized				
Investments held by broker-dealers:				
U.S. government securities				6,542
Mutual funds				26
General pooled securities lending cash collateral				27,090
Total				$ 60,133

Repurchase agreements relate to the Department's securities lending program (see Note 5). Because Water Services did not have any of its securities lent under its own program at June 30, 2003, there are no repurchase agreements at that date.

NOTE 5: Securities Lending Transactions

In December 1999, the Department initiated a securities lending program managed by its custodial bank. The bank lends up to 20% of the investments held in Water Services' plan assets held in the postretirement benefits trust fund for securities, cash collateral or letters of credit equal to 102% of the market value of the loaned securities and interest, if any. The Department can sell collateral securities only in the event of borrower default. Both the investments purchased with the collateral received and the related liability to repay the collateral are reported on the balance sheets. A summary of Water Services' securities lending transactions as of June 30, 2003 and 2002 is as follows (amounts in thousands):

	June 30, 2003		June 30, 2002	
Securities lent for cash collateral	Fair value of underlying securities	Collateral value	Fair value of underlying securities	Collateral value
U.S. government and agency securities	$ -	$ -	$ 6,542	$ 6,691

The lending agent provides indemnification for borrower default. There were no violations of legal or contractual provisions and no borrower or lending agent default losses during fiscal years 2003 and 2002.

General Investment Pool Program

The Department also participates in the City's securities lending program through the pooled investment fund. The City's program has substantially the same terms as the Department's direct securities lending program. The Department recognizes its proportionate share of the cash collateral received for securities loaned and the related obligation for the general investment pool. As of June 30, 2003 and 2002, Water Services' attributed share of cash collateral and the related obligation from the City's program was $40 and $27 million, respectively.

Management believes that participation in these securities lending programs results in no credit risk exposure to the Department because the amounts owed to the borrowers exceed the amounts the borrowers owe to the Pool.

NOTE 6: Long-term Debt

Long-term debt outstanding as of June 30, 2003 consists of revenue bonds and refunding revenue bonds due serially in varying annual amounts, and other long-term debt, as follows (amounts in thousands):

Bond Issues	Date of Issue	Effective Interest Rate	Fiscal Year of Last Scheduled Maturity	Principal Outstanding
Revenue Bonds				
Refunding Issue of 1998	10/15/98	4.689%	2035	235,730
Issue of 2001, Series A	02/01/01	5.202%	2042	311,565
Issue of 2001, Series B	02/28/01	Variable	2036	325,000
Issue of 2001, Series C	11/15/01	4.788%	2017	3,983
Issue of 2003, Series A	01/07/03	5.084%	2044	300,000
Issue of 2003, Series B	03/06/03	4.014%	2031	201,875
	Total principal amount			1,378,153
	Unamortized debt-related costs (including net loss on refundings)			(46,583)
	Debt due within one year (including current portion of variable rate debt)			(47,104)
				1,284,466
Other Long-term Debt				
Loan payable to California Department of Water Resources (CDWR)	12/27/2001	2.320%	2022	13,252
	Current portion of loan from CDWR			(528)
				12,724
				$ 1,297,190

Revenue bonds generally are callable ten years after issuance. The Department has agreed to certain covenants with respect to bonded indebtedness. Significant covenants include the requirement that Water Services' net income, as defined, will be sufficient to pay certain amounts of future annual bond interest and of future annual aggregate bond interest and principal maturities. Revenue bonds and refunding bonds are collateralized by the future revenues of Water Services.

NOTE 6: (continued)

Long term debt activity

Water Services had the following activity in long-term debt during fiscal year 2003 (amounts in thousands):

	Balance at June 30, 2002	Additions	Reductions	Balance at June 30, 2003	Current Portion
Long term debt, including loan from CDWR	$ 1,000,414	501,875	(205,099)	$ 1,297,190	$ 47,632

New issuances

Fiscal Year 2003

In January 2003, the Department issued $300 million of Water Services fixed rate bonds. The net proceeds were deposited into the construction fund to be used for water system capital improvements. In March 2003, the Department issued $202 million of Water Services fixed rate bonds to refund the Water Works Refunding Revenue Bonds, Issue of 1993 and Second Issue of 1993. Based on interest cost of 4.0% for the fixed nte bonds, the refunding is expected to decrease total debt payments over the life of the new issues by approximately $15 million and is expected to result in present value savings of approximately $10 million. These transactions resulted in a net loss for accounting purposes of $15 million which was deferred and will be amortized through 2030.

Fiscal Year 2002

In November 2001, the Department issued $4 million of Water Services fixed rate bonds as part of the Mini Bond Program for employees and retirees. Water Services' Mini-Bond Program allows for a maximum total issuance of $50 million. The net proceeds were deposited into the construction fund to be used for water system capital improvements.

In May 2001, the Department entered into a loan agreement with the California Department of Water Resources (CDWR). The loan agreement allows for a total maximum loan of $17 million, at a fixed interest rate of 2.32%. In December 2001, the Department received $13 million under the agreement. The proceeds are being used to fund water quality capital improvements.

In September 2003, Water Services received the remaining $4 million from CDWR under its loan agreement. As such, Water Services expects to begin making principal payments under this arrangement beginning in fiscal year 2004.

NOTE 6: (continued)

Outstanding debt defeased

As discussed above, Water Services defeased certain revenue bonds in prior years by placing cash or the proceeds of new revenue bonds in irrevocable trusts to provide for all future debt service payments on the old bonds. Accordingly, the trust account assets and the liability for the defeased bonds are not included in Water Services' financial statements. At June 30, 2003, the following revenue bonds outstanding are considered defeased (amounts in thousands):

Bond Issues	Principal Outstanding
Issue of 1994	$ 48,500
Issue of 1995	45,250
Issue of 1999	100,000
	$ 193,750

Variable rate bonds

The variable rate bonds currently bear interest at daily and weekly rates (ranging from 0.85% to 1.05% as of June 30, 2003). The Department can elect to change the interest rate period of the bonds, with certain limitations. The bondholders have the right to tender the bonds to the tender agent on any business day with seven days prior notice. The Department has entered into Standby Agreements with a syndicate of commercial banks in an initial amount of $325 million to provide liquidity for these bonds. The initial and extended Standby Agreements expire in March 2004 and November 2004.

NOTE 6: (continued)

Bonds purchased under the agreements will bear interest that is payable quarterly at the greater of the Federal Funds Rate plus 0.50% or the bank's announced base rate, as defined. The unpaid principal of bonds purchased is payable in ten equal semi-annual installments, commencing after the termination of the agreement. At its discretion, the Department has the ability to convert the outstanding bonds to fixed rate obligations, which cannot be tendered by the bondholders. These bonds have been classified as long term on the balance sheets as the liquidity facilities give the Department the ability to refinance on a long term basis and the Department intends to either renew the facilities or exercise its right to tender the debt as a long term financing. That portion which would be due in the next fiscal year in the event that the outstanding variable rate bonds were tendered and purchased by the commercial banks under the Standby Agreements, has been included in the current portion of long term debt and was $32.5 million as of June 30, 2003 and 2002.

Advance refunding bonds

In prior years, Water Services established irrevocable escrow trusts with proceeds from the issuance of refunding bonds. During fiscal year 2002, bonds with a par value of $83 million were refunded using proceeds from the balance in the restricted escrow investments. Escrow investments of $5 million (stated at fair value as of June 30, 2003) will be used to pay debt service on bonds presently included in long-term debt. During fiscal 2002, all remaining advance refunding bonds were reclassified to long-term debt as the bonds to be refunded were called. Interest expense from refunding bonds and interest income earned on related escrow investments are included in investment income.

NOTE 6: (continued)

Scheduled principal maturities and interest

Scheduled annual principal maturities and interest are as follows (amounts in thousands):

	Principal	Interest and Amortization
Fiscal years ending June 30,		
2004	$ 15,132	$ 55,209
2005	14,987	55,186
2006	13,230	54,730
2007	13,967	54,154
2008	17,391	53,286
2009 - 2013	95,027	253,888
2014 - 2018	117,730	225,116
2019 - 2023	94,191	199,981
2024 - 2028	122,020	179,681
2029 - 2033	214,630	158,669
2034 - 2038	259,410	129,712
2039 - 2043	335,210	55,915
2044	78,480	-
Total Requirements	$ 1,391,405	$ 1,475,527

The scheduled maturities for the fiscal year ending June 30, 2004 exclude $32.5 million in variable rate bonds classified as short term for reporting purposes as described above. Interest and amortization includes interest requirements for variable rate debt, using the average variable debt interest rate in effect at June 30, 2003, of 0.997%.

Fair value

The fair value of long-term debt is $1.3 and $0.9 billion at June 30, 2003 and 2002, respectively. Management has estimated fair value based on the present value of interest and principal payments on the long-term debt and refunding bonds, discounted using current interest rates obtainable by the Department for debt of similar quality and maturities.

NOTE 7: Retirement, Disability, and Death Benefit Insurance Plan

The Department has a funded contributory retirement, disability, and death benefit insurance plan covering substantially all of its employees. The Water and Power Employees' Retirement, Disability and Death Benefit Insurance Plan (the Plan) operates as a single-employer benefit plan to provide pension benefits to eligible Department employees and to provide disability and death benefits from the respective insurance funds. Plan benefits are generally based on years of service, age at retirement and the employee's highest 12 consecutive months of salary before retirement. Active participants who joined the plan on or after June 1, 1984 are required to contribute 6% of their annual covered payroll. Participants who joined the plan prior to June 1, 1984 contribute an amount based upon an entry-age percentage rate. The Department contributes $1.10 for each $1.00 contributed by participants plus an actuarially determined annual required contribution as determined by the Plan's independent actuary. The contributions are allocated between Water Services and Energy Services based on the current year labor costs.

The Retirement Board of Administration (the Retirement Board) is the administrator of the Plan. The Plan is subject to provisions of the Charter of the City of Los Angeles and the regulations and instructions of the Board of Water and Power Commissioners (the Board of Commissioners). The Plan is an independent pension trust fund of the Department.

Plan amendments must be approved by both the Retirement Board and the Board of Commissioners. The Plan issues separately available financial statements on an annual basis.

Water Services' allocated share of annual pension cost (APC) and net pension obligation (NPO) consists of the following (amounts in thousands):

	Year Ended June 30,	
	2003	2002
Annual required contribution	$ 9,857	$ -
Interest on net pension asset	(3,357)	(3,379)
Adjustment to annual required contribution	5,003	5,223
APC (including $5 million and $1 million of amounts capitalized in fiscal 2003 and 2002, respectively)	11,503	1,844
Department contributions	(15,136)	(9,348)
Shared operating expenses (see Note 9)	4,929	478
Change in NPO	1,296	(7,026)
NPO (asset) at beginning of year	(59,848)	(52,822)
NPO (asset) at end of year	$ (58,552)	$ (59,848)

NOTE 7: (continued)

Annual required contributions are determined through actuarial valuations using the entry age normal actuarial cost method. The actuarial value of assets in excess of the Department's actuarial accrued liability (AAL) was being amortized by level contribution offsets over the period ending June 30, 2003. As a result of an April 2000 amendment to the Plan, the amortization period was changed to rolling fifteen-year periods effective July 1, 2000.

In accordance with actuarial valuations, the Department's required contribution rates are as follows:

Acturial Valuation Date June 30	Normal Cost	Surplus Amortization	Required Contribution Rate
2002	10.97%	-2.64%	8.66%
2001	10.64%	-13.65%	0.00%
2000	10.59%	-14.52%	0.00%

The significant actuarial assumptions include an investment rate of return of 8%, projected inflation-adjusted salary increases of 5.5%, and postretirement benefit increases of 3%. The actuarial value of assets is determined using techniques that smooth the effects of short-term volatility in the market value of investments over a four-year period. Plan assets consist primarily of corporate and government bonds, common stocks, mortgage-backed securities and short-term investments.

Trend information for fiscal years 2003, 2002, and 2001 for Water Services is as follows (amounts in thousands):

Year ended June 30,	NPO (asset)	Percentage of APC Contributed	APC
2003	$ (58,552)	84%	$11,503
2002	$ (59,848)	400%	$ 1,844
2001	$ (52,822)	413%	$ 1,674

NOTE 7: (continued)

The following schedule provides information about the Department's overall progress made in accumulating sufficient assets to pay benefits when due, prior to allocations to Water Services and Energy Services (amounts in thousands):

Actuarial Valuation Date June 30,	Actuarial Value of Assets	AAL	Actuarial Assets over AAL	Funded Ratio	Covered Payroll	Overfunding as a % of Covered Payroll
2002	$ 5,790,263	$ 5,714,525	$ 75,738	101%	$ 430,398	18%
2001	$ 5,833,275	$ 5,306,263	$ 527,012	110%	$ 403,266	131%
2000	$ 5,605,856	$ 5,082,960	$ 522,896	110%	$ 369,509	142%

Disability and death benefits

Water Services' allocated share of disability and death benefit plan costs and administrative expenses totaled $4, $3, and $3 million for each of the fiscal years 2003, 2002 and 2001, respectively.

NOTE 8: Health Care Costs

The Department provides certain health care benefits to active and retired employees and their dependents. The health plan is administered by the Department, and the Retirement Board and the Board of Water and Power Commissioners have the authority to approve provisions and obligations. Eligibility for benefits is dependent on a combination of age and service of the participants pursuant to a predetermined formula. Any changes to these provisions must be approved by the Board. The Department pays a maximum subsidy of health plan premiums. Participants choosing plans with a cost in excess of the subsidy are required to pay the difference. The total number of active and retired Department participants entitled to receive benefits was approximately 14,200 at June 30, 2003.

The allocated cost to Water Services of providing such benefits amounted to $42, $39, and $33 million for fiscal years 2003, 2002, and 2001, respectively. Of these costs, $17, $17, and $12 million were capitalized and the remainder was charged to expense for fiscal years 2003, 2002, and 2001, respectively.

Postretirement benefits

The Department accounts for postretirement benefits in accordance with SFAS No. 106, *"Employers' Accounting for Postretirement Benefits Other Than Pensions"*, which requires that the cost of postretirement benefits be recognized as expense over employees' service periods.

Water Services' allocated share of postretirement benefit costs is summarized as follows (amounts in thousands):

	Year ended June 30,		
	2003	2002	2001
Service cost	$ 6,873	$ 5,578	$ 4,248
Interest cost	22,746	19,344	16,339
Expected return on plan assets	(1,369)	(1,347)	(1,319)
Amortization of transition obligation	5,163	5,148	5,148
Amortization of prior service costs	4,777	2,617	2,617
Amortization of actuarial losses	2,625	2,782	-
	$ 40,815	$ 34,122	$ 27,033

NOTE 8: (continued)

The funded status and the accrued benefit cost related to postretirement benefits for the Department, prior to allocations to Water Services and Energy Services, are summarized as follows (amounts in thousands):

	June 30,	
	2003	2002
Change in benefit obligation:		
Benefit obligation at beginning of year	$ 941,626	$ 802,849
Service cost	20,154	16,407
Interest cost	66,704	56,893
Actuarial losses	846,000	101,713
Benefits paid	(43,132)	(36,236)
Benefit obligation at end of year	1,831,352	941,626
Change in fair value of plan assets:		
Fair value of plan assets at beginning of year	81,493	77,669
Department contribution	96,000	-
Actual return on plan assets	7,232	3,824
Fair value of plan assets at end of year	184,725	81,493
Funded status	1,646,627	860,133
Unrecognized net loss	1,124,256	295,221
Unrecognized transition obligation	152,721	167,863
Unrecognized prior service cost	39,771	47,469
Accrued benefit cost	$ 329,879	$ 349,580
Water Services' allocated share of accrued postretirement liability	$ (99,186)	$ (105,391)

Weighted average actuarial assumptions used in determining postretirement benefit costs are as follows:

	June 30,		
	2003	2002	2001
Discount rate	5.75%	7.25%	7.25%
Expected return on plan assets	6.25%	6.50%	6.50%

NOTE 8: (continued)

Plan assets consist primarily of commercial paper, United States Government and governmental agency securities, and corporate bonds. In addition to having set up a trust fund, the Department currently pays benefits on a "pay as you go" basis. No funding policy has been established for the future benefit to be provided under this plan, however in fiscal year 2003, the Department made an employer contribution of $96 million.

For measurement purposes, a 10.0% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2003; the rate was assumed to decrease gradually to 5.5% in 2012 and remain at that level thereafter. For the dental plan, an 8.0% annual rate of increase in the per capita cost was assumed for 2003; the rate was assumed to decrease gradually to 5.5% in 2008 and remain at that level thereafter. The effect of a 1% change in these assumed health care cost trend rates would increase or decrease the Department's total benefit obligation by approximately $387 or $298 million, respectively. In addition, such a 1% change would increase or decrease the aggregate service and interest cost components of net periodic benefit cost by approximately $13 or $10 million, respectively.

During fiscal year 2000, the Department began contributing toward dental coverage for retirees enrolled in a Department-sponsored plan. This amendment resulted in a $46 million increase in the Department's accumulated postretirement benefit obligation at June 30, 2000. Water Services' allocated $11 million share of this increase is being amortized through 2008, the remaining average service period. This change also resulted in an $12, $12, and $11 million increase in postretirement benefit costs for fiscal years 2003, 2002 and 2001, respectively, of which $4 million in each of these years, was allocated to Water Services.

NOTE 9: Shared Operating Expenses

Water Services shares certain administrative functions with the Department's Energy Services. Generally, the costs of these functions are allocated on the basis of the benefits provided. Operating expenses shared with Energy Services were $603, $514, and $455 million for fiscal years 2003, 2002 and 2001, respectively, of which $219, $186, and $154 million were allocated to Water Services.

NOTE 10: Loss on Asset Impairment and Abandoned Projects

During fiscal year 2001, management approved the sale of one of its administrative facilities and Water Services reported its portion of the loss on asset impairment of $12 million. The completion of the sale was expected to occur within 12 to 24 months for a total original purchase price of $50 million, which was below the total asset carrying value. During fiscal year 2002, management became aware that the facility has mold in the structure. Management and the purchaser of the facility each conducted a study to determine an estimated cost for mold cleanup. As of June 30, 2002, no estimate was available to record a clean-up liability, however, as of June 30, 2003, management approved the sale of this administrative building for a reduced price of $37 million, which is pending Board approval. This reduction in price caused Water Services to recognize an additional loss of $3.4 million as of June 30, 2003.

During fiscal year 2002, management formally abandoned certain water projects and reported a loss on abandonment totaling approximately $16 million in the statement of revenue, expenses, and changes in fund net assets. Projects abandoned included design work related to a well field and a filter plant, and small construction projects that will not be completed.

NOTE 11: Commitments and Contingencies

Transfers to the reserve fund of the City of Los Angeles

Under the provisions of the City Charter, Water Services transfers funds at its discretion to the reserve fund of the City. Pursuant to covenants contained in the bond indentures, the transfers may not be in excess of the increase in fund net assets before transfers to the reserve fund of the City, of the prior fiscal year. Such payments are not in lieu of taxes and are recorded as a non-operating expense in the statement of revenue, expenses, and changes in fund net assets.

The Department authorized total transfers of $27.5, $27.2, and $25.5 million in fiscal years 2003, 2002 and 2001, respectively, from Water Services to the reserve fund of the City. The Department expects to make an additional transfer declaration from Water Services of approximately $27.6 million during fiscal year 2004.

NOTE 11: (continued)

Operating lease

Water Services utilizes an advanced wastewater treatment facility owned and operated by a separate department of the City. The use of this facility is accounted for as an operating lease. Estimated expenditures for fiscal year 2004 are approximately $2 million to operate and maintain this asset. There are no minimum rental payments that the Department has to make. However, the Department is obligated to reimburse the other City department for that department's operating and maintenance costs to operate the facility, estimated to be about $2 million per year, for a term of 25 years. Water Services will also pay additional monies to the other City department, if revenues generated by Water Services exceed the costs of operation and maintenance as defined by the agreement. Water Services does not expect to pay such additional amounts as it does not expect that a net operating profit will be achieved based on current demand for recycled water.

Surface Water Treatment Rule

The State of California Surface Water Treatment Rule (SWTR) imposes increased filtration requirements at any open distribution reservoirs exposed to surface water runoff. The Department has had four major reservoirs in its system subject to the SWTR: Upper and Lower Hollywood, Lower Stone Canyon, and Encino. To comply with the SWTR, the Department has designed projects to remove these reservoirs from regular service through construction of larger pipelines and storage facilities. These changes will improve water quality while maintaining flexibility in the water system.

The Hollywood Water Quality Improvement Project was completed in July 2002. Upper and Lower Hollywood Reservoirs were removed from service and functionally replaced by two 30 million gallon tanks and additional pipelines. Construction began on the Encino project in December 2002 and the Stone Canyon Water Quality Improvement Project is scheduled to begin construction in December 2003. As of June 30, 2003, the cost of SWTR compliance related to engineering studies and construction activities at the four reservoirs and for the addition of key pipelines in the San Fernando Valley totaled $319 million and are expected to reach $539 million at completion in 2007.

NOTE 11: (continued)

Owens Valley

During 1997, the Great Basin Unified Air Pollution Control District (the District) adopted an initial State Implementation Plan, as amended, and an implementing order requiring the Department to initiate pollution control measures to control particulate matters emitting from the Owens Dry Lake bed. The Department disputed the remediation measures imposed by the original order; however, in July of 1998 the City and the District entered in an historic Memorandum of Agreement (MOA) to mitigate the dust problem. The MOA delineated the dust producing areas on the lakebed that needed to be controlled, specified what measures must be used to control the dust, and specified a timetable for implementation of the control measures. The MOA called for phased implementation to permit the effectiveness of the control measures to be evaluated and modifications to be made as the control measures were being installed.

The MOA was incorporated into a formal air quality State Implementation Plan (SIP) by the District. This SIP was approved by the United States Environmental Protection Agency on October 4, 1999. Currently, the District is in the process of revising the SIP and will adopt it late this year. The revised SIP will define the additional boundaries and areas required to be controlled on the lakebed. The Department has been allowed to examine the District's methodology to determine the additional areas to be controlled. As a result of those efforts the District has agreed to a total of 30 square miles that will be required to be controlled. That amount includes the areas the City agreed to and has completed. In the MOA the City committed to 1) completing at least 10 square miles of dust controls by the end of 2001, 2) completing an additional 3.5 square miles by 2002, 3) completing an additional 3.0 square miles by 2003, 4) completing the additional areas delineated in District's revised 2003 SIP. The SIP will demonstrate that upon completion of the City's work, emissions from Owens Lake bed will have been reduced so that the Owens Valley Planning Area will attain and maintain the federal Clean Air Act ambient air quality standards for particulate matter. The federal Clean Air Act requires that Owen Lake meet ambient air quality standards by the end of 2006.

NOTE 11: (continued)

The MOA specified that the City must choose from amongst 3 control measures the District has certified as Best Available Control Measures for Owens Lake. The three measures are Shallow Flooding, Managed Vegetation, and Gravel. To date, the City has completed construction on and is operating approximately 19 square miles of dust control measures. Therefore, the city is nearly two-thirds complete with its obligation. The first phase of dust control implementation, completed December 2001, consists of 13.5 square miles of Shallow Flooding. Shallow Flooding involves flooding the area to be controlled until it is either inundated with a few inches of water or the soil becomes thoroughly saturated to the surface with water. The second phase of dust control implementation, completed in July 2002, consists of about four square miles of Managed Vegetation. Managed Vegetation involves growing native vegetative cover that will hold the shifting and emissive lakebed in place, locking up the dust. The third phase of dust control implementation, completed in March 2003, consists of one and a third square miles of additional Shallow Flooding. Planning and design are currently underway for the additional 11 square miles to be specified in District's revised SIP. An additional two to four construction phases are expected to meet these requirements. The Department is evaluating the budget for the program based on the District's SIP.

As of June 30, 2003, the Department has incurred capital costs of approximately $212 million associated with the Owens Dry Lake. Based on the anticipated 2003 SIP, management estimates that the total capital related costs of implementing the pollution control measures through 2006 will be approximately $415 million.

Capital expenditures

Water Services has budgeted approximately $380 million of capital expenditures for fiscal year 2004.

Litigation

A number of claims and suits are pending against the Department for alleged damages to persons and property and for other alleged liabilities arising out of its operations. In the opinion of management, any ultimate liability, which may arise from these actions, are not expected to materially impact Water Services' financial position, changes in fund net assets, or cash flows as of June 30, 2003.

NOTE 11: (continued)

Risk management

Water Services is subject to certain business risks common to the utility industry. The majority of these risks are mitigated by external insurance coverage obtained by Water Services. For other significant business risks, however, Water Services has elected to self-insure. Management believes that exposure to loss arising out of self-insured business risks will not materially impact Water Services' financial position, changes in fund net assets, or cash flows as of June 30, 2003.

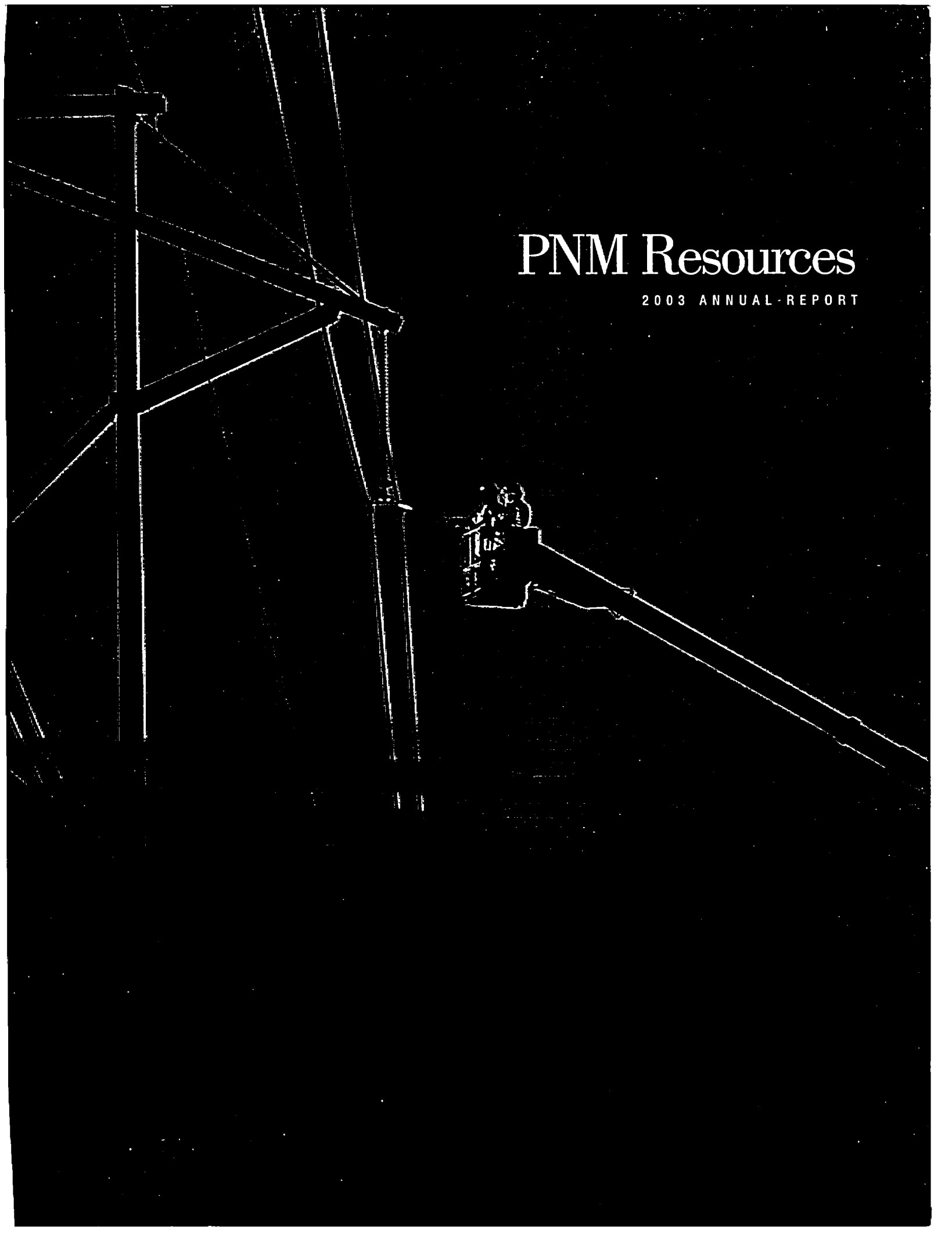
Credit risk

Financial instruments, which potentially expose the Department to concentrations of credit risk, consist primarily of retail receivables. The Department's retail customer base is concentrated among commercial, industrial, residential and governmental customers located within the City. Although the Department is directly affected by the City's economy, management does not believe significant credit risk exists at June 30, 2003, except as provided in the allowance for losses. The Department manages its credit exposure by requiring credit enhancements from certain customers and through procedures designed to identify and monitor credit risk.

NOTE 12: Subsequent Events

On December 17, 2003, the Board approved the reduced sale price of the administrative facility described in Note 10. The reduced price remains subject to City Council approval.

Also on December 17, 2003, the Retirement Board adopted a change in the actuarial asset valuation method for the Department's Retirement, Disability and Death Benefit Insurance Plan from the four-year smoothing method to recognizing the unrecognized returns for each of the last five years (but not before July 11, 2001) over a five-year period.



PNM Resources

2003 ANNUAL REPORT

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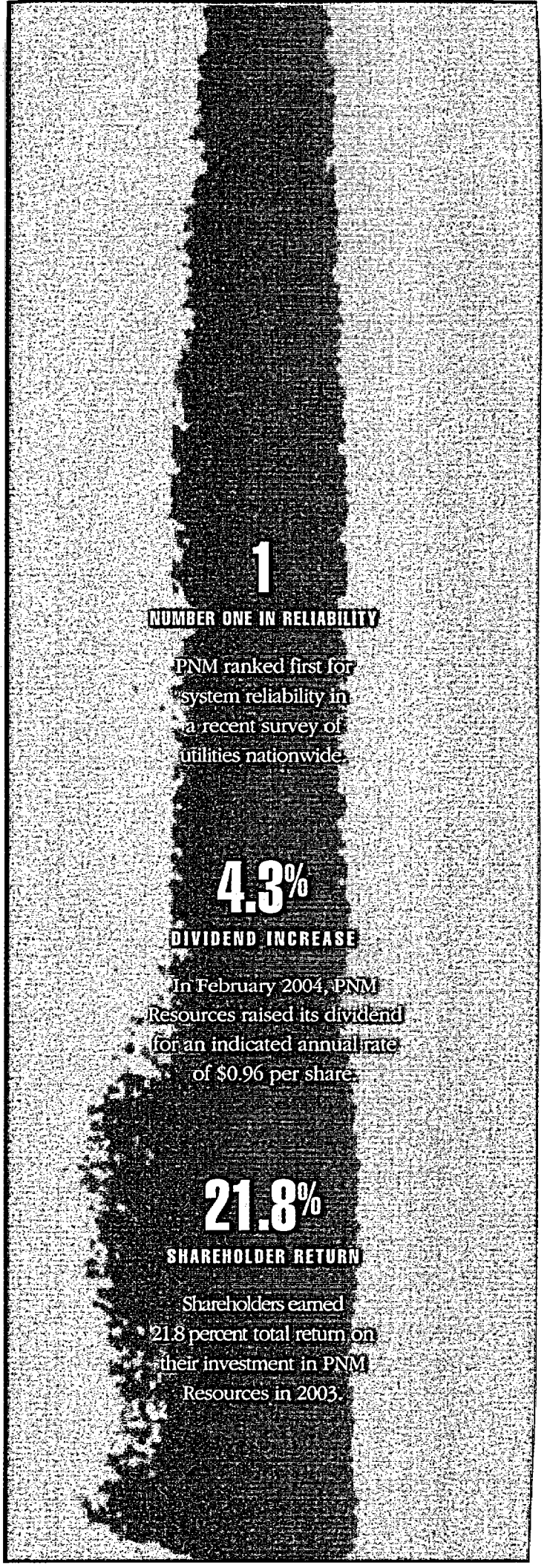
INVESTOR HIGHLIGHTS

Dollars in thousands, except per share amounts

	2003	2002	PERCENTAGE CHANGE	5-YEAR ANNUAL CHANGE RATE
Financial Data				
Operating Revenues	$1,455,714	$1,118,694	30.1%	5.36%
Operating Expenses	$1,337,122	$1,016,920	31.5%	5.96%
Net Earnings Available for Common	$ 95,173	$ 63,686	49.4%	2.88%
Retained Earnings	$ 503,069	$ 444,651	13.1%	17.17%
Return on Average Common Equity	9.30%	6.40%	45.3%	(0.21%)
Common Share Data				
Earnings (Basic)	$ 2.39	$ 1.63	46.6%	3.52%
Earnings (Diluted)	$ 2.37	$ 1.61	47.2%	3.35%
Book Value	$ 27.09	$ 24.90	8.8%	4.45%
Closing Price	$ 28.10	$ 23.82	18.0%	11.58%
Dividends Paid	$ 0.91	$ 0.86	5.8%	2.61%
Average Shares Outstanding (000)	39,747	39,118	1.6%	(0.64%)
Number of Employees	2,637	2,656	(-0.7%)	(0.23%)

NM - Not Meaningful

THE PNM Advantage



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NUMBER ONE IN RELIABILITY

PNM ranked first for system reliability in a recent survey of utilities nationwide.

4.3%

DIVIDEND INCREASE

In February 2004, PNM Resources raised its dividend for an indicated annual rate of $0.96 per share.

21.8%

SHAREHOLDER RETURN

Shareholders earned 21.8 percent total return on their investment in PNM Resources in 2003.

DEAR FELLOW SHAREHOLDERS,

I'm pleased to report another successful year for our company. For PNM Resources, 2003 was a year of solid accomplishment in all areas of our business. On the retail side, we reached new rate agreements for both our electric and our gas utility, and New Mexico finally resolved the 10-year public policy debate over industry restructuring.

In our wholesale operations, we added several new long-term contracts that boost revenues and earnings while helping guard against the uncertainties of price swings in a volatile market.

In power generation, we brought on line a new coal mine that we expect will lower fuel costs at our biggest generating plant and we added our first renewable resource, a 200-megawatt wind power project in eastern New Mexico.

All across the company, our disciplined pursuit of excellence through a structured approach to process improvement helped us to better control expenses even as we achieved higher levels of customer satisfaction.

Those successes all contributed to increased earnings and growing shareholder value. Net earnings for the year were $2.37 per diluted share, up from $1.61 a share in the previous year. That bottom line number included various one-time gains and charges that added a net of $0.42 per share to earnings. Another measure of PNM financial performance is in comparing ongoing earnings (not including one-time gains or charges) of $1.95 per share for 2003, up nearly 8 percent from the previous year. With the $0.92 per share paid in dividends and a $4.28 increase in stock price over the course of the year, PNM Resources shareholders earned a healthy 21.8 percent return on their investment in 2003.

Stability in our core business

Over the past decade, PNM has worked hard to build a strong financial foundation that supports sustained growth in shareholder value. Retained earnings, the fundamental measure of a company's net worth, grew from $445 million at the end of 2002 to $503 million at the end of 2003. By taking advantage of lower interest rates, we were able to cut interest expense by nearly $12 million by refinancing existing debt. We also expanded our line of credit to $300 million to ensure we have the liquidity we need to run and grow our business.

Because about 75 to 85 percent of PNM Resources earnings flow from our electric and gas utility in New Mexico, one of our primary goals over the past several years has been to gain predictability and stability in the revenues we generate from this core business.

We made significant progress toward that goal in 2003. At the beginning of the year the state legislature officially dropped plans to introduce electric competition in New Mexico. The legislation recognizes the need for a reasonable transition away from the originally proposed restructured markets back to a vertically integrated industry in New Mexico by allowing us to expand our wholesale marketing presence and maintain joint dispatch of both regulated and non-regulated generation.

In January 2003, the state Public Regulation Commission accepted a negotiated agreement setting PNM electric rates through 2007. The agreement lowered customer electric rates by $21 million in September 2003, with a second $14 million reduction planned for September 2005, while still offering the opportunity to earn a fair return on investment in our electric utility. To improve the return on our gas utility, PNM next negotiated a $22 million increase in gas service rates and fees. Together, the two new rate agreements serve as a solid base for earnings growth over the next several years.

Our personal commitment to reliability

Over the past several years, I've seen a fundamental change in our corporate culture as we grapple with the tough questions about how we measure ourselves, what our standards are, and how we hold ourselves accountable. As a result, we have been able to defy the myth that quality costs more. We have been able to improve the quality of service to our customers at the same time we reduced costs, so that PNM customers today are paying lower rates than they were almost 20 years ago.

Our PNM slogan, "A Personal Commitment to New Mexico," has been embraced by employees throughout the company. It's this commitment our folks make every day to their jobs, to you as shareholders and to the communities they serve that makes the difference.

Integrity in all our business dealings

Providing value to shareholders, support for the communities we serve, and a challenging, rewarding environment for our employees are the bedrock principles that define the PNM corporate culture.

"Do the Right Thing," the code of corporate ethics adopted by PNM nearly 10 years ago, has provided us with a solid foundation for ethical business behavior and positioned the company well to comply with the requirements of the Sarbanes-Oxley Act. We take seriously our responsibility to give you the information you need to form your own opinion on your company's progress. By providing revenue and margin numbers on each business segment, we are trying to make it easier for our owners to trace the source of earnings and understand the factors that drive financial results.

Innovation to meet changing needs

While we take a conservative approach both to financial management and in our growth strategy, we are always seeking out new and better ways to serve customers, cut costs, and improve your company's environmental performance.

One of the 2003 PNM initiatives I'm most proud of is our participation in the New Mexico Wind Energy Center, a 200-Megawatt "wind farm" that taps an inexhaustible energy source to help produce the power the West needs, without any use of scarce water or any air pollution.

In the first months of our voluntary "Sky Blue" program, more than 4,000 customers agreed to pay a small monthly premium to buy a portion of their energy from renewable generation resources. We also see a market for renewable energy among PNM wholesale customers. In 2003 we made our first major sale, of 50 megawatts of wind energy credits, to an Arizona utility. We look forward to a growing trade that will allow New Mexico's renewable resources to supplement or replace fossil fuel power.

Solid growth in our wholesale business

Our wholesale strategy aims to build long-term relationships based on mutual advantage and confidence. With a vital commodity like electricity, customers want to deal with a supplier they can trust to provide solid value for a fair price. That is the PNM commitment to our customers, both retail and wholesale.

The PNM reputation for reliability and fair dealing helped us add several new clients to our customer base in 2003. Over the course of the year, we signed new long-term contracts to provide 330 megawatts of power to customers in Arizona, Nevada and California. These new power sales contracts balance the more than 550 megawatts in generating capacity PNM has added to our portfolio over the past four years. Including our obligation to serve our New Mexico customers, nearly three-quarters of our generation capacity is now committed under long-term arrangements.

Goals for 2004

In last year's annual report, I listed five objectives we intended to accomplish in 2003: to continue to improve operational performance, expand our wholesale business, improve the return in our gas utility, add a renewable energy component to the PNM generation mix, and pursue new growth opportunities.

We achieved all five of those goals.

We have already achieved one of the major goals that we set for 2004 when we made a commitment to improve our credit rating. In early 2004, both Moody's Investors Services and Standard & Poor's raised PNM's credit rating one notch. The improved credit ratings position the company for continued growth.

Pursuing new growth opportunities remains on our to do list in 2004. In 2003, adding several important new long-term contracts helped improve earnings by nearly 8 percent for the year. To continue that upward trend, we need to acquire more power in the near future to serve our expanding wholesale business and meet the growing demand in our home service territory. We are going to be very cautious about how we add those new resources. We are going to do it at the right price and in the right location.

Another 2004 goal is to work with New Mexico regulators to find ways to better manage the impact of high natural gas costs both for PNM gas customers and for our own gas-fired power plants.

With retail electric and gas rates set, earnings growth in 2004 will depend on continued growth in our home service territory, the continued expansion of our wholesale power business, and our continued success in controlling expenses and improving productivity through our company-wide efforts at process improvement.

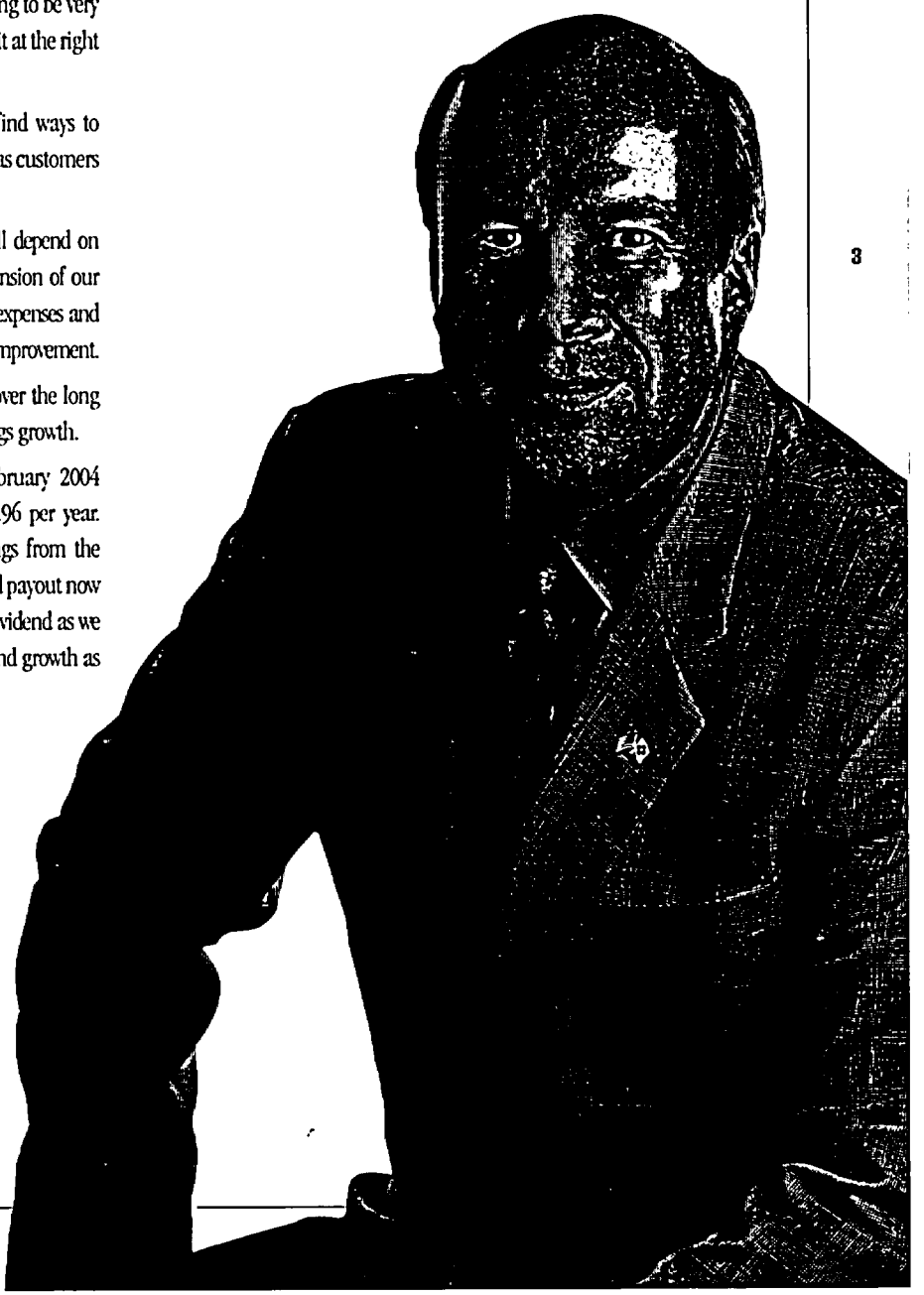
Our aim is to grow earnings by between 5 and 6 percent a year over the long term. We exceeded that target in 2003 with nearly 8 percent earnings growth.

We raised the dividend for the fourth consecutive year in February 2004 bringing the PNM Resources common stock dividend up to $0.96 per year. Strategically, our target is to pay out 50 to 60 percent of earnings from the regulated utility side of our business as dividends. Since the dividend payout now is a bit under our 60 percent limit, we still have room to grow the dividend as we go forward. As long as our earnings streams hold up, we see dividend growth as an important component of shareholder value.

Thank you for your continued confidence in PNM,

Sincerely,

JEFFRY E. STERBA
Chairman, President and Chief Executive Officer of PNM Resources, Inc.

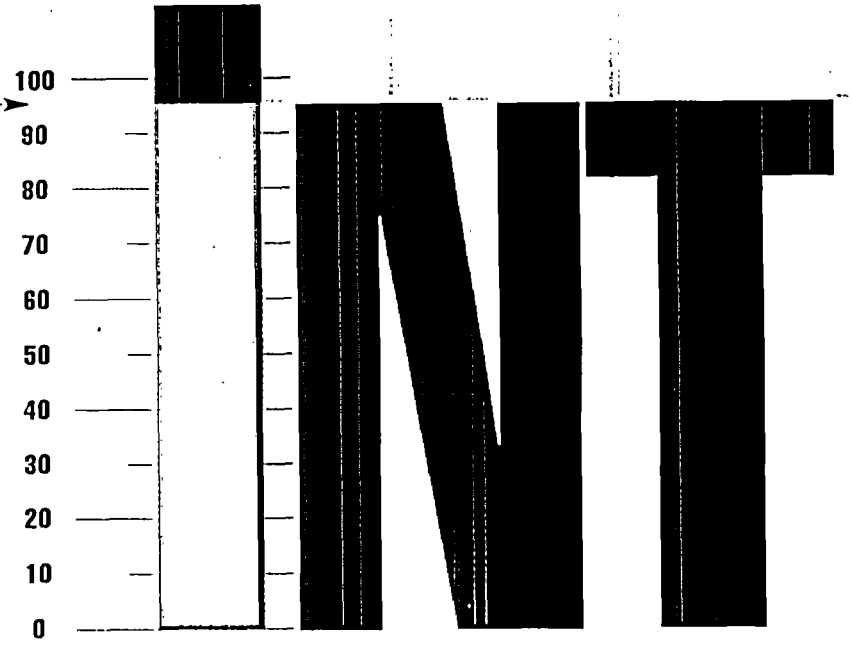


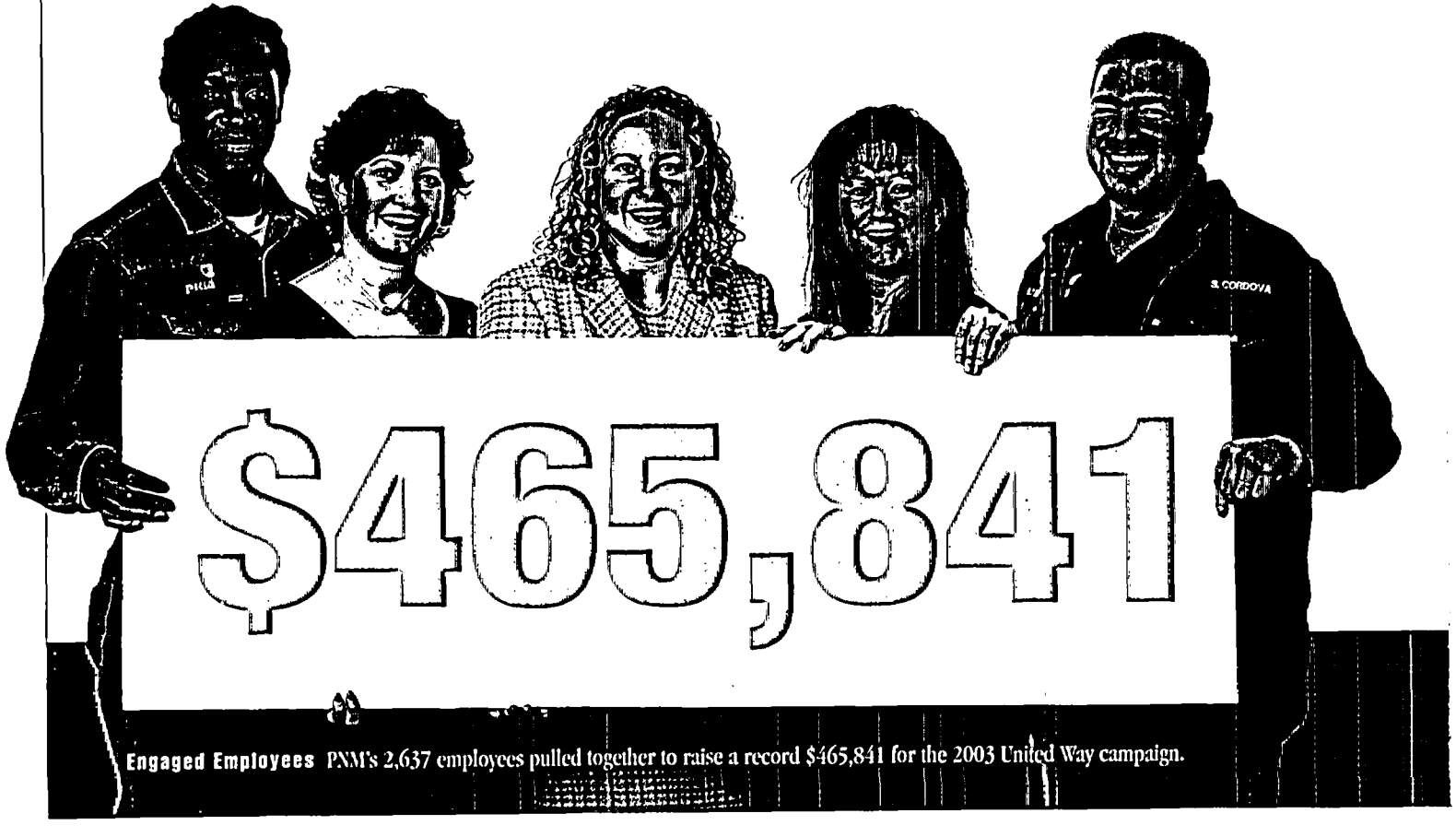
DOING THE RIGHT THING IS GOOD BUSINESS

Our goal: To be New Mexico's most valued community partner and leading corporate citizen, demonstrating the highest integrity in all our dealings – with shareholders, with customers, with suppliers and vendors, with employees, and with the communities we serve.

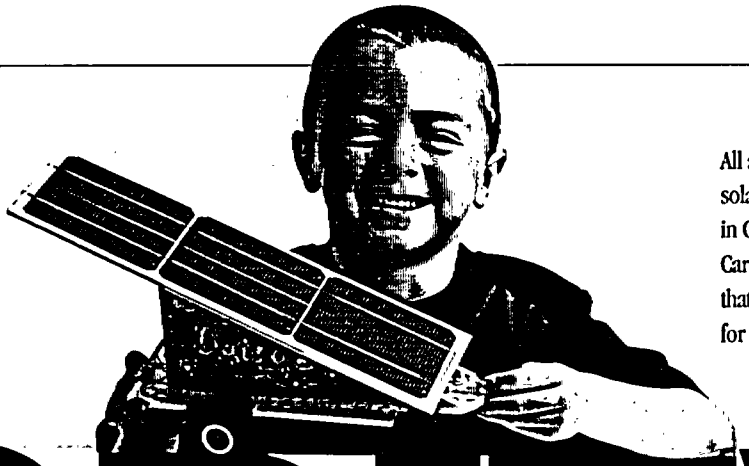
95.2%

PNM Resources corporate governance ranks among the top 5 percent of companies nationwide, according to an independent investor advisor. Key criteria in the evaluation include the independence, expertise and involvement of the board of directors and the policies the company has in place to assure that management remains focused on the best interest of shareholders.



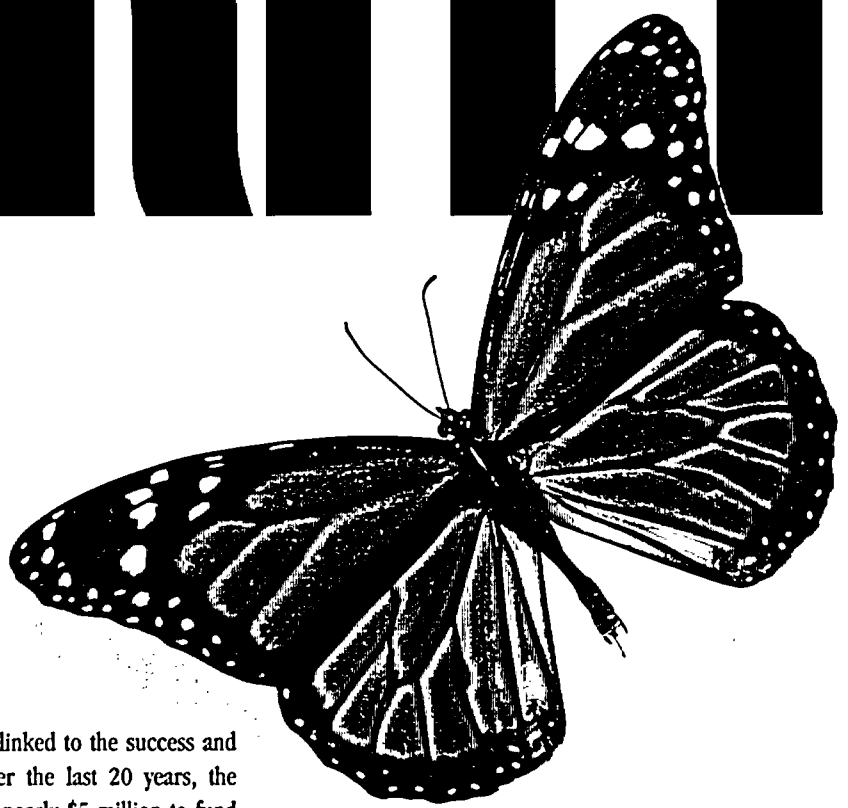


Engaged Employees PNM's 2,637 employees pulled together to raise a record $465,841 for the 2003 United Way campaign.



All across New Mexico, from a solar-powered model car contest in Gallup to a playground in Carlsbad, we support initiatives that aim to enrich the quality of life for the people of our home state.

EGRITY



The success of PNM Resources is directly linked to the success and vitality of the communities we serve. Over the last 20 years, the nonprofit PNM Foundation has distributed nearly $5 million to fund nonprofit projects to meet community needs. Many other efforts, like the PNM Butterfly Pavilion in the Albuquerque Biopark, are supported with company contributions and the volunteer efforts of PNM employees.

Environmental Sustainability

The PNM commitment is to achieve sustainability in our company and our community, working wisely to meet the energy needs of the present without compromising the legacy we leave future generations.

Long Term Contracts

"Most of our wholesale business is based on long-term contract sales to municipal utilities, rural co-ops, and other utilities. Over three-quarters of PNM's total generating capacity is devoted to serving our retail base and long-term wholesale customers."

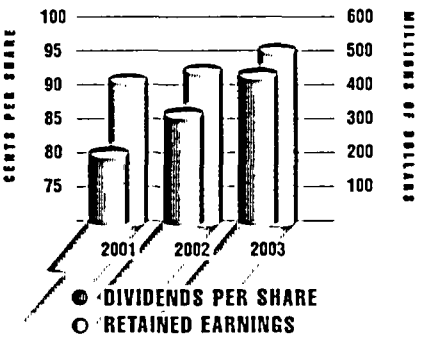
THOMAS NESMITH *Manager, Marketing & Forward Contracts*

An agreement approved by New Mexico regulators early in 2003 sets PNM retail electric rates through the end of 2007. In January 2004, regulators approved a $22 million increase in gas rates and fees.

A BRIGHT FUTURE

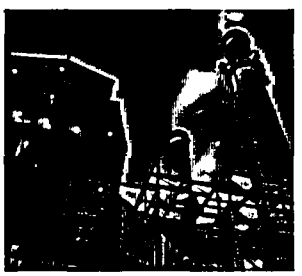
The number of PNM electric customers increased about 3.1 percent in 2003. Growth in PNM's home service territory has been above the national rate for most of the last 10 years. According to the New Mexico Department of Labor, employment in the Albuquerque metro area is projected to increase about 25 percent by 2010, significantly above the national average.

STABILITY



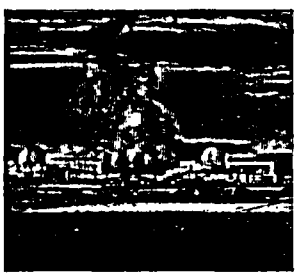
CONSERVATIVE FINANCIAL STRATEGY

The PNM financial strategy aims at reducing interest expense, maintaining a healthy cash flow and maintaining the company's investment-grade credit rating. In 2003, we refinanced nearly $500 million in older, high-cost debt, cutting interest costs by about $12 million a year.



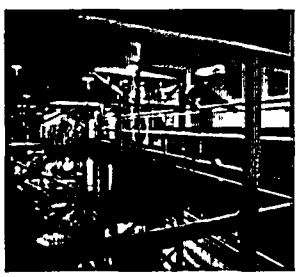
COAL POWER

One of the largest coal-fired power plants in the West, San Juan Generating Station in northwestern New Mexico is the flagship of the PNM generating fleet. San Juan provides nearly 60 percent of the power needs of the company's customers.



NUCLEAR POWER

PNM owns a 10.2 percent share in the 3,800-megawatt Palo Verde nuclear plant, located about 50 miles west of Phoenix, Arizona. Palo Verde provides about 30 percent of PNM power needs.



NATURAL GAS

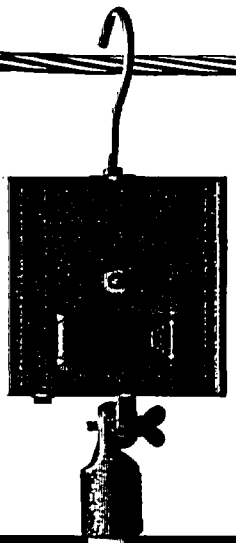
In 2002, PNM added two new, natural gas-fired generating plants to help meet peak demand during the summer or take advantage of opportunities in the wholesale market.

RENEWABLES

In 2003, PNM contracted to buy the full output of the 200-megawatt New Mexico Wind Energy Center, operated by FPL Energy. One of the largest wind power projects in the U.S., the project serves both PNM retail and wholesale customers.

EFFICIENT USE OF GENERATING RESOURCES

The balance of coal, nuclear, gas and renewables in the PNM fleet gives us the opportunity to make the most of each of these resources. Rather than limit certain plants to serving only retail customers, any PNM power not needed to serve retail load is available for the wholesale market.



The AP-10 Phase Identification System, commercialized by PNM Resources subsidiary Avistar, quickly and easily identifies the current phase on a "hot" line. Avistar has already sold a number of pre-production units of this patented technology to other utilities.

INNOV

ENABLING ORDINARY PEOPLE TO ACCOMPLISH EXTRAORDINARY THINGS.

The PNM emphasis on process improvement is about finding ways to do things better in all parts of our company. Applying leading-edge technology solutions to do everything from bringing wind power to the grid in record time to getting the lights back on as fast as possible after an outage benefits both customers and shareholders.

SUSTAINABILITY: In December 2003 PNM Resources adopted a visionary new plan that sets ambitious five-year goals in:

WATER CONSERVATION.
To reduce the amount of fresh water used in PNM power generation by 15 to 20 percent.

AIR QUALITY.
To reduce the emissions coming out of our power plants by up to 15 percent.

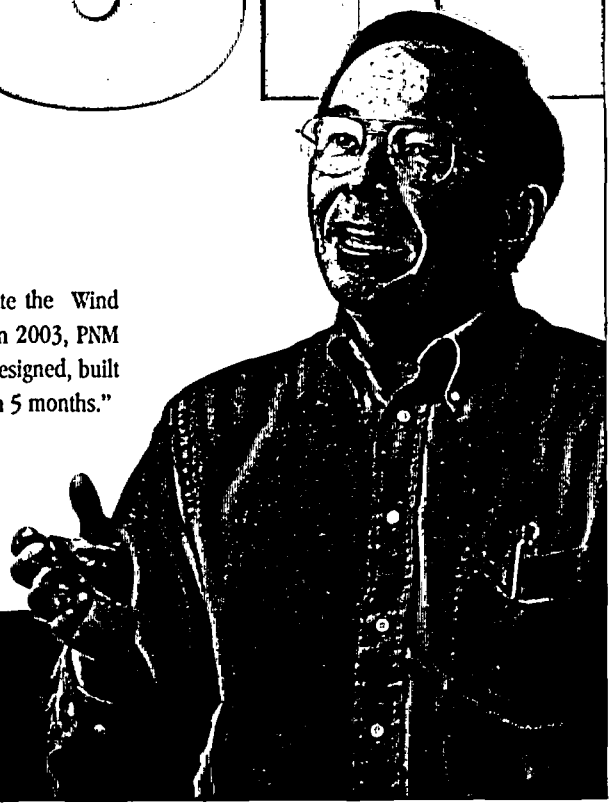
WASTE.
To reduce the waste streams generated by our company by 15 percent.

Mounted on a remote-control robot, the Mutual Inductance Bridge technology developed by Avistar helps engineers decide where boiler maintenance is needed, minimizing costly power plant outage time.

ATION

"When we were called on to integrate the Wind Energy Center into the electric grid in 2003, PNM engineers rose to the challenge. We designed, built and energized the project in less than 5 months."

GENE WOLF *Principal Engineer*



RENEWABLE SUCCESS

More than 4,000 retail customers have signed up to buy the clean, renewable electricity generated by the New Mexico Wind Energy Center.

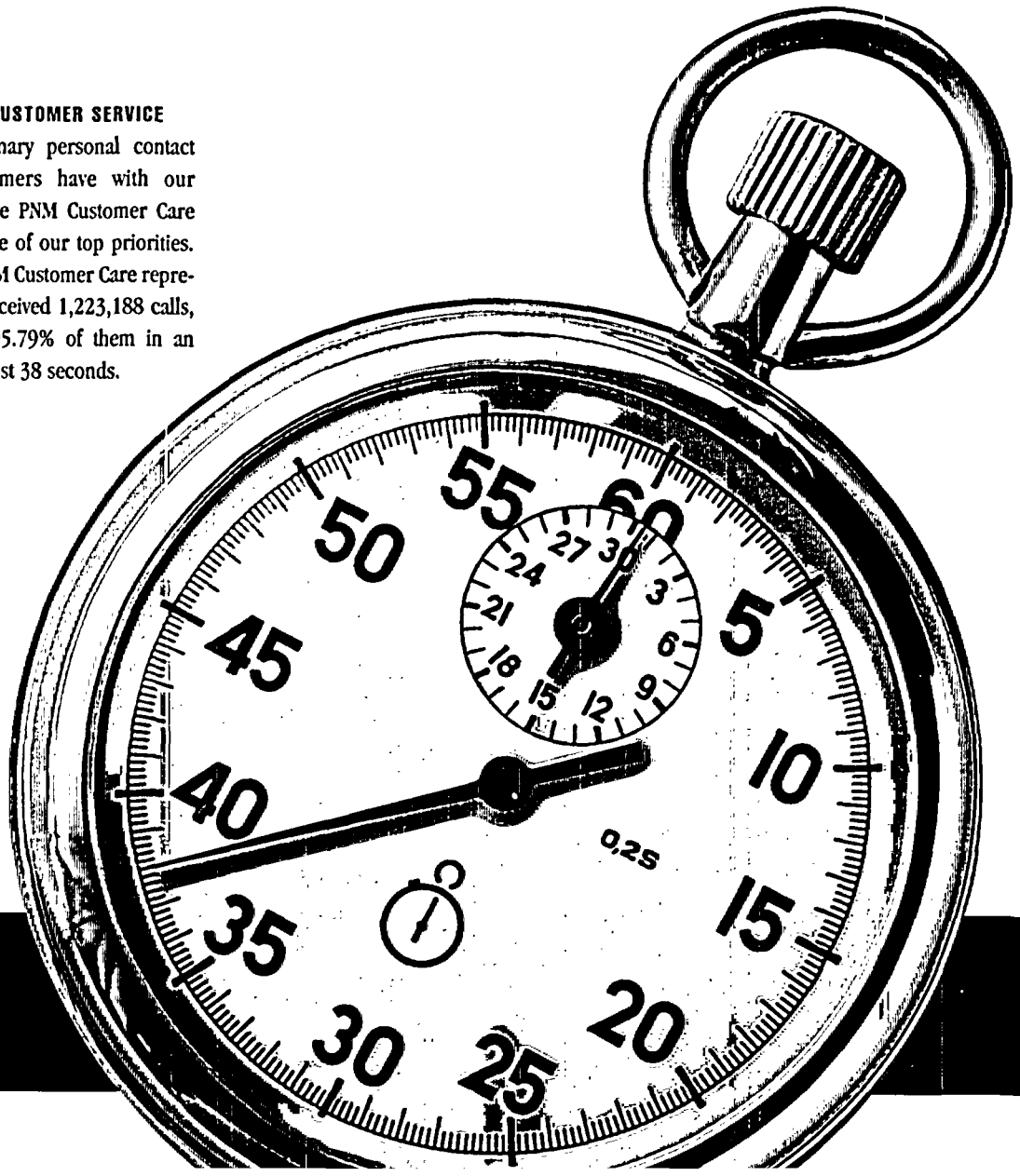
RELIABILITY

A COMPANY YOU CAN COUNT ON.

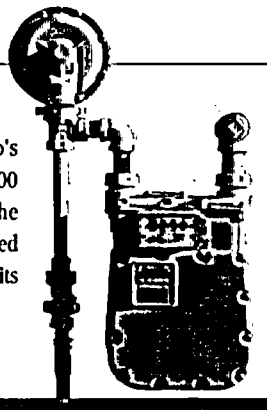
Customers want us to keep the lights on and the gas flowing to their homes and businesses. They expect a quick, courteous and efficient response when they call with a problem or question. They want superior value for their money. They expect us to value safety above all.

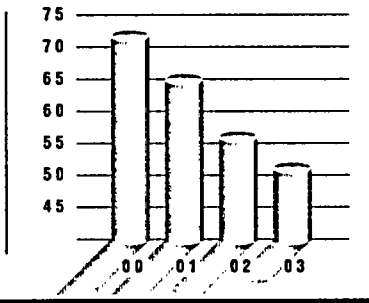
SUPERIOR CUSTOMER SERVICE

As the primary personal contact most customers have with our company, the PNM Customer Care Center is one of our top priorities. In 2003, PNM Customer Care representatives received 1,223,188 calls, answering 95.79% of them in an average of just 38 seconds.

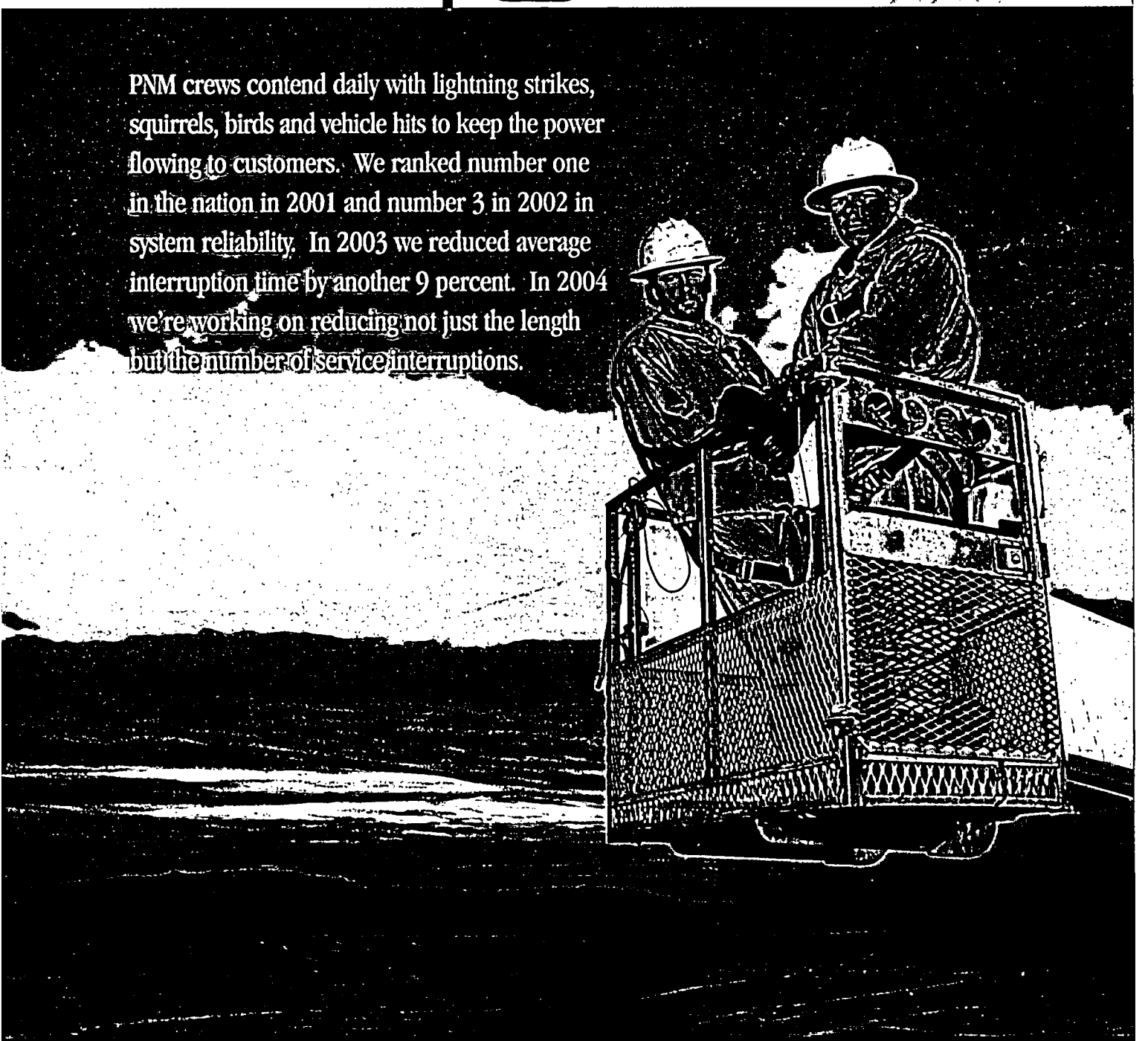


PNM GAS SERVICES PNM is New Mexico's largest gas utility serving more than 450,000 customers in communities throughout the state. Since 1991, the company has invested $300 million in upgrading and expanding its 12,378 mile gas system.





PNM crews contend daily with lightning strikes, squirrels, birds and vehicle hits to keep the power flowing to customers. We ranked number one in the nation in 2001 and number 3 in 2002 in system reliability. In 2003 we reduced average interruption time by another 9 percent. In 2004 we're working on reducing not just the length but the number of service interruptions.

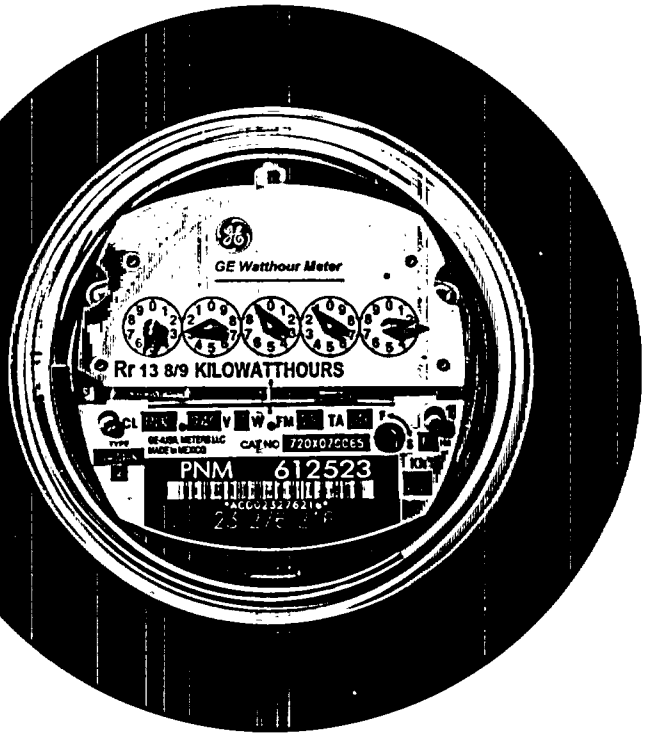


PNM Linemen Wes Rolan and Paul Allison are trained to work "barehanded" on live transmission lines, reducing the amount of time lines are shut down for maintenance. Instead of insulating the worker from the line, special techniques and equipment are used to isolate the worker from the ground like a bird sitting on the wire.

PROFITABLE GROWTH.

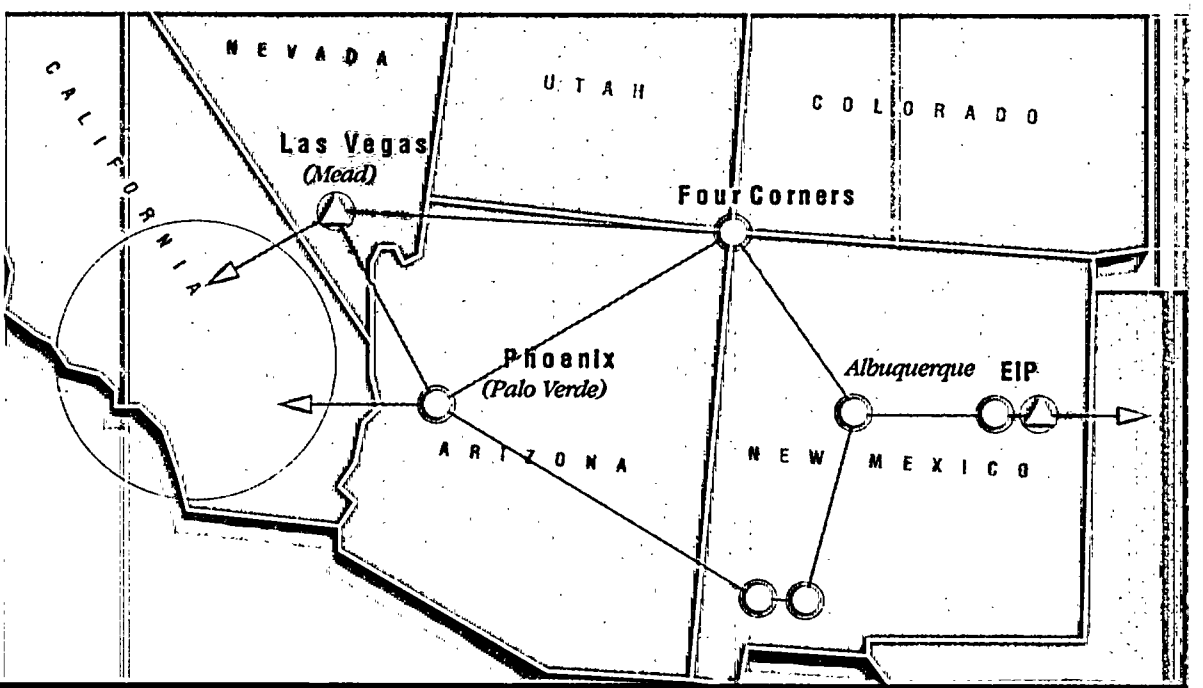
The PNM goal is to grow earnings by an average of 5 to 6 percent a year over the long term, maintaining a balance between our wholesale power sales and our core regulated electric and gas utility operations.

GRO



STRATEGIC LOCATION

PNM has access to critical transmission hubs in the Four Corners, at Palo Verde in eastern Arizona and near Lake Mead in southern Nevada. We also own one of the few interconnections between the Western power grid and the Southwest Power Pool. Those key links put PNM Power Marketing in reach of the largest power markets in the West.



1917 PNM begins as Albuquerque Gas & Electric Co.

1930 Albuquerque population 27,000, NM population 423,000

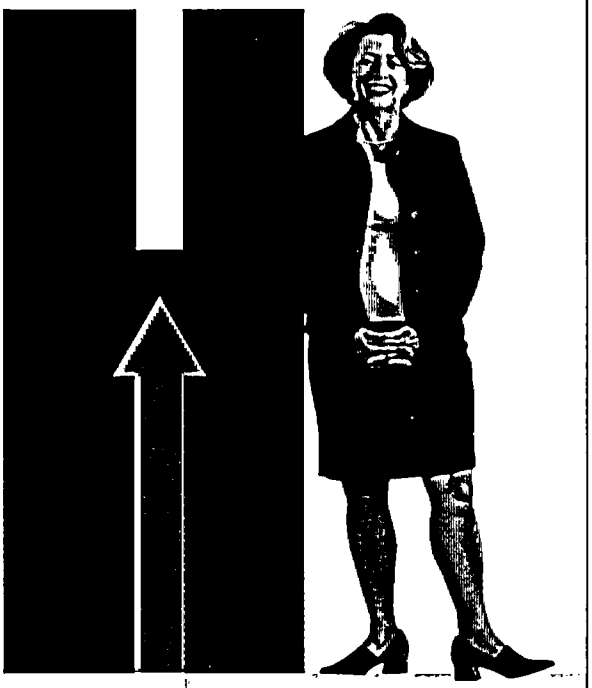
1958 Reeves Station, a natural gas-fired plant, goes on line.

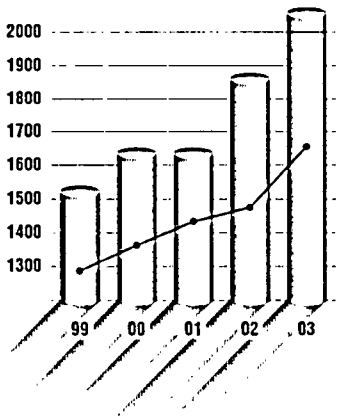
1963 Four Corners Power Plant, one of the largest coal-fired generating stations in U.S., goes on line.

1972 PNM is listed on the New York Stock Exchange.

On a 1 to 10 scale of customer satisfaction, PNM scores 8.2 with business customers like Mary Anne Giangola, CFM, Facility Manager of TransCore. Utility average nationwide is 7.6.

WTH



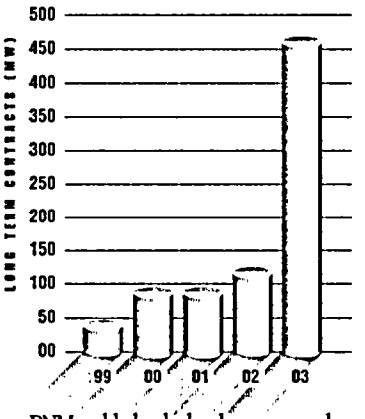


SYSTEM PEAK

Not including the impact of warmer weather, PNM electric retail growth was about 3 percent in our New Mexico service territory last year. System peak reached a new record high of 1,661 megawatts in the summer of 2003.

GROWING CAPACITY

To serve our growing retail and wholesale business, PNM has added 553 MW of generation resources over the last three years.



PNM added wholesale power sales contracts totaling 330 megawatts in 2003. Sales to other utilities and large wholesale customers in the West totaled 11.8 million MWh last year.

1973 San Juan Generating Station, with a generating capacity of 1,800 gross megawatts, goes on-line.

1985 PNM reaquires Gas Company of New Mexico

1986 Palo Verde Nuclear Generating Station, the most productive nuclear power plant in the U.S., goes on line.

2000 Albuquerque population: 442,000, NM population: 1,819,001

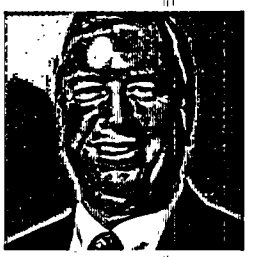
2003 The New Mexico Wind Energy Center, the world's third-largest wind generation project, goes on line.

BOARD OF DIRECTORS

JEFFRY E. STERBA
Chairman, President and Chief Executive Officer of PNM Resources, Inc., Age 49, Director since 2000

ROBERT G. ARMSTRONG
President of Armstrong Energy Corporation, Age 57, Director since 1991

committees:
Governance and Public Policy
Audit and Ethics



JULIE A. DOBSON
Chairman of TeleBright Inc., Age 47, Director since 2002

committees:
Audit and Ethics - Chair
Finance

THEODORE F. PATLOVICH
Retired Vice Chairman and Senior VP of Loctite Corporation, Age 76, Director since 2000

committees:
Human Resources and Compensation
Finance

BONNIE S. REITZ
Retired Senior Vice President Sales and Distribution Continental Airlines, Age 51, Director since 2002

committees:
Human Resources and Compensation
Governance and Public Policy

ADELMO E. ARCHULETA
President and Chief Executive Officer of Molzen-Corbin & Associates Age 53, Director since 2003

committees:
Audit and Ethics
Human Resources and Compensation

R. MARTIN CHAVEZ, Ph.D.
Chairman and Chief Executive Officer of Klodex, Inc., Age 40, Director since 2001

committees:
Finance - Chair
Audit and Ethics

MANUEL T. PACHECO, Ph.D.
President, University of Missouri System, Age 62, Director since 2001

committees:
Governance and Public Policy - Chair
Human Resources and Compensation

ROBERT M. PRICE
President of PSV, Inc., Age 73, Director since 1992

committees:
Human Resources and Compensation - Chair
Finance

JOAN B. WOODARD, Ph.D.
Executive Vice President and Deputy Director for Sandia National Laboratories, Age 51, Director since 2003

committees:
Governance and Public Policy
Finance

OFFICERS OF PNM RESOURCES

Jeffry E. Sterba, 49, Chairman, *President and CEO* • Roger J. Flynn, 61, *Executive VP, COO** • Alice A. Cobb, 56, *Senior VP, People Services and Development* John R. Loyack, 40, *Senior VP, CFO* • Patrick T. Ortiz, 54, *Senior VP, General Counsel and Secretary* • Eddie Padilla, Jr., 50, *Senior VP, Power Marketing and Development* • William J. Real, 55, *Senior VP, Public Policy* • Barbara L. Barsky, 59, *VP, Investor Relations* • Ernest T. C'de Baca, 50, *VP, Governmental Affairs* • Terry R. Horn, 51, *VP and Treasurer* • Thomas G. Sategna, 50, *VP, Corporate Controller*

OFFICERS OF PNM (In addition to above)

Melvin J. Christopher, 43, *VP, Energy Supply and Marketing* • Patrick J. Goodman, 54, *VP, Power Production* • Sarita P. Loehr, 46, *VP, Operations and Engineering* • Cindy E. McGill, 47, *VP, Customer and Market Services* • John H. Myers, 46, *VP, Construction and Reliability* • Joanne C. Reuter, 49, *VP, Regulatory Affairs*

** retiring 6.30.04*

Effective as of March 1, 2004

FINANCIAL INFORMATION

Disclosure Regarding Forward Looking Statements

Statements made in this filing that relate to future events or the Company's expectations, projections, estimates, intentions, goals, targets and strategies are made pursuant to the Private Securities Litigation Reform Act of 1995. Readers are cautioned that all forward-looking statements are based upon current expectations and are subject to risk and uncertainties. The Company assumes no obligation to update this information.

Because actual results may differ materially from expectations, projections, estimates, goals and targets, the Company cautions readers not to place undue reliance on these forward-looking statements. Future financial results will be affected by a number of factors, including interest rates, weather, fuel costs, changes in supply and demand in the market for electric power, wholesale power prices, market liquidity, the competitive environment in the electric and natural gas industries, the performance of generating units and transmission system, state and federal regulatory and legislative decisions and actions, the recoverability of regulatory assets, the outcome of legal proceedings, changes in applicable accounting principles and the performance of state, regional and national economies.

SELECTED FINANCIAL DATA

The selected financial data and comparative operating statistics should be read in conjunction with the consolidated financial statements, the notes to consolidated financial statements and Management's Discussion and Analysis of Financial Condition and Results of Operations.

PNM Resources Inc. and Subsidiaries (In thousands except per share amounts and ratios)

	2003	2002	2001	2000	1999
Total Operating Revenues	$ 1,453,714	$ 1,118,694	$ 2,254,178	$ 1,526,835	$ 1,121,362
Earnings from Continuing Operations	$ 58,552	$ 63,686	$ 149,847	$ 100,360	$ 79,028
Net Earnings	$ 95,173	$ 63,686	$ 149,847	$ 100,360	$ 82,569
Earnings per Common Share					
Continuing Operations	$ 1.47	$ 1.63	$ 3.83	$ 2.64	$ 1.93
Basic	$ 2.39	$ 1.63	$ 3.83	$ 2.54	$ 2.01
Diluted	$ 2.37	$ 1.61	$ 3.77	$ 2.53	$ 2.01
Cash Flow Data					
Net cash flows provided from operating activities	$ 228,692	$ 97,359	$ 327,346	$ 239,515	$ 219,045
Net cash flows used in investing activities	$ (101,567)	$ (200,427)	$ (407,014)	$ (157,500)	$ (55,886)
Net cash flows generated (used) by financing activities	$ (118,133)	$ 78,382	$ 385	$ (94,723)	$ (98,040)
Total Assets	$ 3,378,629	$ 3,247,227	$ 3,127,602	$ 3,092,494	$ 2,911,731
Long-Term Debt, including current maturities	$ 987,210	$ 980,092	$ 953,884	$ 953,828	$ 988,489
Common Stock Data					
Market price per common share at year end	$ 28.10	$ 23.82	$ 27.95	$ 26.81	$ 16.25
Book value per common share at year end	$ 27.09	$ 24.90	$ 25.87	$ 23.42	$ 21.79
Average number of common shares outstanding	39,747	39,418	39,118	39,487	41,038
Cash dividend declared per common share	$ 0.92	$ 0.88	$ 0.80	$ 0.80	$ 1.00
Return on Average Common Equity	9.3%	6.4%	15.5%	11.1%	9.4%
Capitalization					
Common stock equity	51.9%	49.5%	50.8%	48.6%	46.7%
Preferred stock without mandatory redemption Requirements	0.6	0.7	0.6	0.7	0.7
Long-term debt, less current maturities	47.5	49.8	48.6	50.7	52.6
	100.00%	100.00%	100.00%	100.00%	100.00%

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following is management's assessment of the Company's financial condition and the significant factors affecting the results of operations. This discussion should be read in conjunction with the Company's consolidated financial statements and related notes. Trends and contingencies of a material nature are discussed to the extent known.

Overview

The Holding Company is an investor-owned holding company of energy and energy related companies. Its principal subsidiary, PNM, is an integrated public utility primarily engaged in the generation, transmission and distribution of electricity; transmission, distribution and sale of natural gas within the State of New Mexico; and the sale and marketing of electricity in the Western United States.

Competitive Strategy

The Company is positioned as a "merchant utility," primarily operating as a regulated energy service provider. The Company is also engaged in the sale and marketing of electricity in the competitive energy marketplace. As a utility, PNM has an obligation to serve its customers under the jurisdiction of the PRC. As a wholesale electricity provider, PNM markets excess production from the utility, as well as unregulated generation, into a competitive marketplace. As part of its electric wholesale power operation, it purchases wholesale electricity in the open market for future resale or to provide energy to retail customers in New Mexico when the Company's generation assets cannot satisfy demand. The wholesale operations utilize a net asset-backed strategy, whereby the Company's aggregate net open position for the sale of electricity is covered by the Company's forecasted excess generation capabilities.

As it currently operates, the Company's principal business segments, whose operating results are regularly reviewed by the Company's management, are Utility Operations and Wholesale Operations ("Wholesale"). Utility Operations include Electric Services ("Electric"), Gas Services ("Gas") and Transmission Services ("Transmission"). These segments model the resource allocations as mandated in the Global Electric Agreement (see Note 13 – "Commitments and Contingencies – Global Electric Agreement" in the Notes to Consolidated Financial Statements). Electric consists of the distribution and generation of electricity for retail electric customers in New Mexico. Gas includes the transportation and distribution of natural gas to end-users. Transmission consists of the transmission of electricity to third parties as well as to Electric and Wholesale. Wholesale consists of the generation and sale of electricity into the wholesale market based on three product lines, that include long-term contracts, forward sales and short-term sales.

The Utility Operations strategy is directed at supplying reasonably priced and reliable energy to retail customers through customer-driven operational excellence, high quality customer service, cost efficient processes, and improved overall organizational performance.

The Wholesale Operations strategy calls for increased net asset-backed energy sales supported by long-term contracts and the wholesale market, whereby the Company's aggregate net open forward electric sales position, including short term sales, forward sales and long-term contracts, is covered by its forecasted excess generation capacity. The net asset-backed sales are actively monitored by management by the use of stringent risk management policies. The Company's future growth plans call for approximately 75% of its new generation portfolio to be committed through long-term contracts as required by the Global Electric Agreement. Growth will be dependent on market development and on the Company's ability to generate funds for the Company's future expansion. Although the current economic environment has led the Company to scale back its expansion plans, the Company will continue to operate in the wholesale market and seek reasonably priced asset additions. Expansion of the Company's generating portfolio will depend on the Company's ability to acquire favorably priced assets at strategic locations and to secure long-term commitments for the purchase of power from the acquired plants.

Overall Outlook

Earnings growth in 2003 was primarily due to the addition of new long-term power contracts, coupled with customer growth in the Company's Utility Operations and the Company's ongoing cost control efforts. The gains made in the Company's Wholesale Operations more than offset a retail electric rate reduction that took effect in September and a reduction in gas utility revenues due to warmer weather in 2003.

Wholesale Operations was the biggest contributor to the Company's earnings growth in 2003, aided by a more stable price environment. The Company continued to grow its wholesale sales by adding long-term contracts to ensure a reliable and sustainable revenue source to support its Wholesale Operations. In 2003, the Company added more than 330 MW's of new long-term contracts, of which contracts for 57 MW's were added in late 2003 or do not commence until 2004. In addition, the Company added 200 MW of generating capacity in 2003 to support retail and enhance wholesale operations. These developments allowed the Company to improve its velocity, the Company's ability to repurchase and remarket previously sold capacity. The Company's velocity ratio, which is defined as total electric wholesale and retail sales divided by total output of its generation plants, increased to 1.9 in 2003 from 1.6 in 2002. These gains were partially offset by extended scheduled outages and unplanned outages at SJGS and PVNGS and the associated increases in purchase power costs.

Retail Operations also contributed to the Company's earnings growth with increased load growth of 3% in Electric and 2% in Gas. The Company benefited from improved efficiencies and cost cutting measures, including lower power production costs. On an operations and maintenance expense ("O&M") per revenue unit of sale basis, the Company's O&M costs decreased significantly from $0.0172 in 2002 to $0.0154 in 2003. The year 2003 was one of the warmest in recent New Mexico history. The warmer temperatures increased retail electric sales during the summer months but significantly reduced demand for natural gas during the colder months.

Certain developments affecting the Company, and which will have a more meaningful impact on its operating results in 2004 are as follows:

- On January 13, 2004, PRC approved a $22 million revenue increase for the Company's gas utility. Increased rates for commercial customers took effect immediately, while the increase for residential customers will begin April 1, 2004.
- On December 22, 2003, the Company entered into an agreement to provide an Arizona municipal utility with up to 35 MW of power. The ten year contract is expected to produce about $6.5 million in revenues for the Company in 2004.
- In the fourth quarter of 2003, the coal mine operations that supply SJGS reached commercial operation status. In addition, the mine completed on schedule its first long-wall mine change-over to a new area of the coal seam. Coal costs in 2003 were significantly lower than in 2002, and although coal costs cannot be predicted with certainty, the Company currently estimates that coal costs will remain lower in 2004 than average 2002 levels.

In 2004, the Company intends to continue its efforts to expand its wholesale business by building on existing relationships and forming new relationships with long-term contract customers. The Company expects its 2004 earnings to benefit from higher gas rates, forecasted lower fuel costs from the new SJGS underground mine and planned productivity improvements. Other factors that will be critical to achieving earnings goals in 2004 include continued stable wholesale market prices and improved plant performance.

Results of Operations

YEAR ENDED DECEMBER 31, 2003 COMPARED TO YEAR ENDED DECEMBER 31, 2002

CONSOLIDATED

The Company's net earnings for the year ended December 31, 2003 were $95.2 million or $2.37 per diluted share of common stock, a 49.5% increase in net earnings compared to $63.7 million or $1.61 per diluted share of common stock in 2002. This increase primarily reflects the cumulative effect of a change in accounting principle for the adoption of SFAS 143 of $37.4 million, net of income taxes, and improved operating performance. This increase was partially offset by the write-off of transition costs of $16.7 million, net of income taxes, that resulted from the repeal of electric deregulation in New Mexico in the first quarter of 2003 and a write-off of $16.6 million, net of income taxes, for costs related to long-term debt refinancing.

The following discussion is based on the methodology that the Company's management uses for making operating decisions and assessing performance of its various business activities. As such, these statements report operating results without regard to the effect of accounting or regulatory changes, and similar one-time items not related to normal operations. See Note 2 – "Segment Information" in the Notes to Consolidated Financial Statements for additional information regarding these results and the consolidated financial statements.

In addition, adjustments related to EITF Issue 02-03 "Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities" and 03-11 "Reporting Realized Gains and Losses on Derivative Instruments that are subject to FASB statement No. 133 and Not Held for Trading Purposes" are excluded. These accounting pronouncements require a net presentation of trading gains and losses and realized gains and losses for certain non-trading derivatives. Management evaluates wholesale operations on a gross presentation basis due to its net-asset-backed marketing strategy and the importance it places on velocity.

Corporate costs, income taxes and non-operating items are discussed only on a consolidated basis and are in conformity with the presentation in the consolidated financial statements.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

UTILITY OPERATIONS

Electric

The table below sets forth the operating results for Electric (In thousands).

	YEAR ENDED DECEMBER 31,		
	2003	2002	VARIANCE
OPERATING REVENUES	$ 543,850	$ 546,939	$ (3,089)
Less: Cost of energy	204,610	194,138	10,472
Intersegment energy transfer	(32,474)	(29,155)	(3,319)
GROSS MARGIN	371,714	381,956	(10,242)
Energy production costs	107,683	113,257	(5,574)
Distribution O&M	19,249	19,987	(738)
Customer related expense	15,524	17,372	(1,848)
Administrative and general	5,362	5,408	(46)
TOTAL NON-FUEL O&M	147,818	156,024	(8,206)
Corporate allocation	65,071	52,878	12,193
Depreciation and amortization	63,428	59,654	3,774
Taxes other than income taxes	17,937	18,251	(314)
Income taxes	20,873	26,779	(5,906)
TOTAL NON-FUEL OPERATING EXPENSES	315,127	313,586	1,541
OPERATING INCOME	$ 56,587	$ 68,370	$ (11,783)

The following table shows electric revenues by customer class and average customers:

ELECTRIC RETAIL REVENUES (In thousands)	YEAR ENDED DECEMBER 31,		
	2003	2002	VARIANCE
Residential	$ 203,710	$ 197,174	$ 6,536
Commercial	252,876	247,800	5,076
Industrial	67,388	82,009	(14,621)
Other	19,876	19,956	(80)
	$ 543,850	$ 546,939	$ (3,089)
AVERAGE CUSTOMERS	396,303	384,478	11,825

The following table shows electric sales by customer class:

ELECTRIC SALES (Megawatt hours)	YEAR ENDED DECEMBER 31,		
	2003	2002	VARIANCE
Residential	2,405,488	2,298,542	106,946
Commercial	3,379,147	3,254,576	124,571
Industrial	1,246,940	1,612,723	(265,783)
Other	247,255	267,070	(19,815)
	7,378,830	7,432,911	(54,081)

Operating revenues decreased $3.1 million or 0.6% over the prior year period primarily due to the transfer of a significant customer from retail to wholesale electric rates in the first quarter of 2003 and a 4% retail electric rate reduction, which became effective in September 2003. Rates will decrease again by 2.5% in September 2005 and remain at that level through 2007. The customer transfer reduced retail revenues $14.3 million. The rate reduction resulted in a decrease in revenues of approximately $6.9 million. These decreases were partially offset by average customer growth of approximately 3.1%. After adjusting 2002 MWh sales for the transfer of the significant customer from retail to wholesale for comparative purposes, retail electric MWh sales increased due to customer growth.

The gross margin, or operating revenues minus cost of energy sold and intersegment energy transfer, decreased $10.2 million or 2.7% over the prior year period. This decrease is due primarily to the rate decrease, an increase in cost of energy due to outages at Palo Verde Nuclear Generating Station ("PVNGS") Unit 2 during the fourth quarter of 2003 for a steam-generator replacement project, and the customer transfer described above of $12.8 million. These decreases were partially offset by customer growth and lower cost of generation.

Total non-fuel O&M expenses decreased $8.2 million or 5.3% over the prior year period. Energy production costs decreased $5.6 million or 4.9% primarily due to 2002 outages at the Four Corners Power Plant ("Four Corners") and Reeves Generating Station ("Reeves"), which did not recur in 2003, for $1.3 million and $1.0 million, respectively and reduced PVNGS plant maintenance costs of $0.5 million due to increased capitalized expenditures related to the steam-generator replacement project. Customer-related expense decreased $1.8 million or 10.6% due to decreased bad debt expense as a result of continued collection efforts and the favorable outcome of a customer bankruptcy proceeding. Depreciation and amortization increased $3.8 million or 6.3% due to a higher depreciable plant base for new service delivery. In addition, lower energy production costs related to decreased decommissioning expenses of $2.7 million were mostly offset by an increase in depreciation expense of $2.2 million for the change in accounting for costs related to asset retirement obligations as required by SFAS 143

Gas

The table below sets forth the operating results for Gas (In thousands).

	YEAR ENDED DECEMBER 31,		
	2003	2002	VARIANCE
OPERATING REVENUES	$ 358,267	$ 277,406	$ 80,861
Less: Cost of energy	228,345	144,333	84,012
GROSS MARGIN	129,922	133,073	(3,151)
Energy production costs	1,930	1,937	(7)
Transmission and distribution O&M	29,515	29,306	209
Customer related expense	16,832	16,607	225
Administrative and general	2,040	2,943	(903)
TOTAL NON-FUEL O&M	50,317	50,793	(476)
Corporate allocation	40,363	33,516	6,847
Depreciation and amortization	22,186	20,673	1,513
Taxes other than income taxes	6,886	7,716	(830)
Income taxes	(1,281)	2,703	(3,984)
TOTAL NON-FUEL OPERATING EXPENSES	118,471	115,401	3,070
OPERATING INCOME	$ 11,451	$ 17,672	$ (6,221)

The following table shows gas revenues by customer and average customers:

GAS REVENUES (In thousands)	YEAR ENDED DECEMBER 31,		
	2003	2002	VARIANCE
Residential	$ 226,799	$ 176,284	$ 50,515
Commercial	72,269	53,734	18,535
Industrial	2,820	2,872	(52)
Transportation*	18,906	17,735	1,171
Other	37,473	26,781	10,692
	$ 358,26	$ 277,406	$ 80,861
Average customers	452,328	443,396	8,932

*Customer-owned gas.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following table shows gas throughput by customer class:

GAS THROUGHPUT (Thousands of decatherms)	YEAR ENDED DECEMBER 31,		
	2003	2002	VARIANCE
Residential	27,416	29,627	(2,211)
Commercial	10,810	12,009	(1,199)
Industrial	485	749	(264)
Transportation*	50,756	44,889	5,867
Other	5,510	4,807	703
	94,977	92,081	2,896

*Customer-owned gas.

Operating revenues increased $80.9 million or 29.2% over the prior year period to $358.3 million, primarily because of higher natural gas prices in 2003 as compared to 2002. PNM purchases natural gas in the open market and resells it at cost of purchase to its retail gas distribution customers. As a result, increases or decreases in gas revenues driven by gas costs do not impact the Company's consolidated gross margin or earnings.

The gross margin, or operating revenues minus cost of energy sold, decreased $3.2 million or 2.4% over the prior year period. This decrease is due mainly to the expiration in January 2003 of a rate rider for the recovery of certain costs of $4.1 million. The price decrease was offset by an increase in volume. Transportation throughput increased by 5.9 million decatherms, or 13.1% driven by gas pipe line extensions, increasing off-system sales. Despite customer growth of 2.0%, volume from other customers decreased 3.0 million decatherms, or 6.3% caused by warmer weather in 2003. In January 2004, the PRC approved a cost of service gas rate increase, which will improve gas earnings by approximately $22 million annually. The Company estimates that approximately two-thirds of this increase will be realized in 2004 earnings due to a delay in implementing the residential increase until April 2004.

Total non-fuel O&M expenses decreased $0.5 million or 0.9% over the prior year period. Administrative and general costs decreased $0.9 million or 30.7% primarily due to lower consulting costs of $1.0 million. Depreciation and amortization increased $1.5 million or 7.3% due to a higher depreciable plant base for new service delivery and transportation gas line extensions. Taxes other than income taxes decreased $0.8 million or 10.8% due to a decrease in property tax of $0.2 million as a result of a change in assessed values and a decrease in PRC supervision and lower inspection fees of $0.6 million.

TRANSMISSION

The table below sets forth the operating results for Transmission (In thousands).

	YEAR ENDED DECEMBER 31,		
	2003	2002	VARIANCE
OPERATING REVENUES:			
External customers	$ 19,453	$ 23,150	$ (3,697)
Intersegment revenues	32,499	31,950	549
TOTAL REVENUES	51,952	55,100	(3,148)
Less: Cost of energy	4,255	3,888	367
GROSS MARGIN	47,697	51,212	(3,515)
Energy production costs	1,051	690	361
Transmission O&M	12,347	14,531	(2,184)
Customer related expense	19	9	10
Administrative and general	1,610	2,216	(606)
TOTAL NON-FUEL O&M	15,027	17,446	(2,419)
Corporate allocation	5,387	4,703	684
Depreciation and amortization	10,104	8,741	1,363
Taxes other than income taxes	2,583	2,464	119
Income taxes	3,179	4,699	(1,520)
TOTAL NON-FUEL OPERATING EXPENSES	36,280	38,053	(1,773)
OPERATING INCOME	$ 11,417	$ 13,159	$ (1,742)

Operating revenues decreased $3.1 million or 5.7% over the prior year period primarily due to lower demand for wheeling of $7.4 million to California from Arizona as a result of lower demand in the California market, partially offset by increased demand for wheeling in New Mexico of $1.7 million and $2.3 million in new 2003 contract revenue. This contract was not renewed for 2004. Cost of energy represents purchased transmission to support transmission offerings. This cost and the resulting gross margin do not fully represent cost of services as these purchases are incidental to the services provided.

Total non-fuel O&M expenses decreased $2.4 million or 13.9% over the prior year period. Transmission O&M decreased $2.2 million or 15.0% due to a decrease in lease costs of $3.3 million for the EIP transmission line, a portion of which was repurchased in April 2003, offset by increased maintenance costs incurred for reliability purposes. Depreciation and amortization increased $1.4 million or 15.6% primarily due to the purchase of additional transmission lines.

WHOLESALE

The table below sets forth the operating results for Wholesale (In thousands).

	YEAR ENDED DECEMBER 31,		
	2003	2002	VARIANCE
OPERATING REVENUES:			
External sales	$ 548,847	$ 343,780	$ 205,067
Intersegment sales	1,535	–	1,535
TOTAL REVENUES	550,382	343,780	206,602
Less: Cost of energy	414,550	262,517	152,033
Intersegment energy transfer	32,474	29,155	3,319
GROSS MARGIN	103,358	52,108	51,250
Energy production costs	29,919	32,507	(2,588)
Transmission and distribution O&M	59	45	14
Customer related expense	711	754	(43)
Administrative and general	8,390	3,199	5,191
TOTAL NON-FUEL O&M	39,079	36,505	2,574
Corporate allocation	5,673	4,023	1,650
Depreciation and amortization	14,230	8,808	5,422
Taxes other than income taxes	3,263	2,619	644
Income taxes	10,116	(3,245)	13,361
TOTAL NON-FUEL OPERATING EXPENSES	72,361	48,710	23,651
OPERATING INCOME	$ 30,997	$ 3,398	$ 27,599

The following table shows revenues by customer class (In thousands):

WHOLESALE REVENUES	YEAR ENDED DECEMBER 31,		
	2003	2002	VARIANCE
Long-term contracts	$ 147,447	$ 58,546	$ 88,901
Forward sales*	166,557	77,560	88,997
Short-term sales	234,843	207,674	27,169
Intersegment sales	1,535	–	1,535
	$ 550,382	$ 343,780	$ 206,602

*Includes mark-to-market gains/(losses).

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following table shows sales by customer class (Megawatt hours):

WHOLESALE SALES	YEAR ENDED DECEMBER 31,		
	2003	2002	VARIANCE
Long-term contracts	2,719,432	844,169	1,875,263
Forward sales	3,597,325	1,336,745	2,260,580
Short-term sales	5,531,019	7,269,240	(1,738,221)
	11,847,776	9,450,154	2,397,622

Operating revenues increased $206.6 million or 60.1% over the prior year period to $550.4 million. This increase in wholesale electric sales primarily reflects additional long-term contract sales and more stable wholesale market conditions. The Company sold wholesale (bulk) power of 11.8 million MWh of electricity for the year ended December 31, 2003, compared to 9.5 million MWh for 2002.

The gross margin, or operating revenues minus cost of energy sold and intersegment energy transfer, increased $51.3 million or 98.4% over the prior year period. A higher gross margin was achieved primarily by additional long-term sales under new and existing contracts, a return to more stable market prices and improved market liquidity. The addition of 273 MW of long-term contracts added $37.4 million or 72.9% of the total gross margin increase for the year. In December 2003 and January 2004, the Company added an additional 57 MW of long-term contracts. In addition, long-term contract margin increased due to the transfer of a significant customer from retail to wholesale. Forward sales margin increased $14.3 million or 27.9% of the total gross margin increase reflecting higher prices. The average price realized by the Company on its forward sales was $46 per MWh in 2003, compared to $37 per MWh in 2002. Liquidity returning to the market helped drive improvement of forward sales, as the Company had velocity of 1.9 vs. 1.6 a year ago. Short-term sales margin decreased $0.4 million or 0.8% of total gross margin due to lower volume from retail growth, increased long-term sales contracts and fewer available resources caused by a significant outage schedule in 2003, mostly offset by higher prices. The average price realized by the Company on its short-term sales was $42 per MWh in 2003, compared to $29 per MWh in 2002. Overall open market sales (forward and short-term sales) averaged $44 per MWh in 2003 versus $33 per MWh in 2002. This increase was partially offset by increased purchased power costs resulting from the 2003 outage schedule, which reduced availability of generation for wholesale sales. In addition, the Company had to buy power in the open market at higher prices to cover its contractual obligations, which resulted in increased purchased power costs of $20.5 million. The Company had a favorable change in the unrealized mark-to-market position of the forward sales portfolio of $1.0 million period-over-period ($3.5 million gain in 2003 versus $2.5 million gain in 2002).

Total non-fuel O&M expenses increased $2.6 million or 7.1% over the prior year period. Energy production costs decreased $2.6 million or 8.0% primarily due to decreased decommissioning costs of $3.1 million and prior period, non-recurring engineering costs of $4.0 million related to the start-up of the Afton plant. These cost decreases were offset by increases of $2.3 million for the operation of the new Afton and Lordsburg gas fired facilities and $1.8 million due to increased Palo Verde Unit 3 outages. Administrative and general costs increased $5.2 million or 162.3% primarily due to transportation and storage costs of $1.2 million for turbines that will be utilized in future construction for merchant plant growth and increased pension and benefits costs of $4.0 million at SJGS and PVNGS. Depreciation and amortization increased $5.4 million or 61.6% primarily due to the addition of Lordsburg and Afton, which added $3.6 million of depreciation expense and an increase of $1.6 million for the change in accounting for asset retirement obligations as required by SFAS 143. Taxes other than income taxes increased $0.6 million or 24.6% primarily due to increased property taxes from the addition of Afton and Lordsburg.

CORPORATE AND OTHER

Corporate administrative and general expenses, which represent costs that are driven primarily by corporate-level activities, is allocated to the business segments and is presented in the corporate allocation line item in the segment statements. These costs increased $19.7 million or 22.4% over the prior year period to $107.9 million. This increase was due to increased pension and benefits expense of $17.9 million, resulting from lower prior-year returns on pension investments and increasing healthcare costs. Consulting expenses increased $1.5 million primarily for Sarbanes-Oxley Act compliance and other strategic corporate initiatives.

Taxes other than income decreased $2.5 million, or 79.6% over the prior year period due to the favorable resolution of certain outstanding tax issues and a decrease in social security taxes from lower payroll costs.

CONSOLIDATED

Other Income and Deductions

Other income increased $4.3 million or 9.0% over the prior year period reflecting higher year-over-year returns on investments of $6.3 million, and an increase in the equity component of AFUDC of $2.6 million. These increases were offset by decreased interest income of $4.5 million due to the redemption of short-term investments early in 2003. Cash from the redemption of these investments was primarily used for the Company's retirement of the EIP long-term debt, debt refinancing, repayment of short-term debt and pension funding (see "Liquidity" below).

Other deductions increased $33.8 million over the prior year period primarily due to a charge of $16.7 million in 2003 for the write-off of transition costs due to the repeal of deregulation in New Mexico and a write-off of $16.6 million for costs related to long-term debt refinancing (see "Financing Activities" below).

Interest Expense

Interest expense increased $4.8 million or 7.8% over the prior year period primarily due to decreased capitalized interest of $3.9 million from the completion of the Afton and Lordsburg gas-fired plants in southern New Mexico. Higher average short term borrowing levels also contributed to the increase.

Income Taxes

The Company's consolidated income tax expense before the cumulative effect of a change in accounting principle was $27.9 million for the year ended December 31, 2003, compared to $33.0 million for the prior year period. The decrease was due to the impact of lower pre-tax earnings. The Company's effective income tax rates for the years ended December 31, 2003 and 2002 were 32.05% and 33.95%, respectively. The decrease in the effective tax rate, year-over-year, was due to an increase in permanent tax differences, resulting from AFUDC and research and development credits in 2003.

CUMULATIVE EFFECT OF A CHANGE IN ACCOUNTING PRINCIPLE

Effective January 1, 2003, the Company adopted Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" ("SFAS 143"). The effect of the initial application of the new standard is reported as a cumulative effect of a change in accounting principle. As a result, the Company recorded income, net of income taxes, of approximately $37.4 million, or $0.93 per diluted common share, representing amounts expensed in prior years for its asset retirement obligations in excess of the actual legal obligations as established under the new accounting standard.

In 2003, the Company changed its valuation date for its pension and post retirement benefits plans from September 30 to December 31 to better reflect the actual plan balances as of the Company's year end balance sheet date. The effect of the change in the pension plans' valuation date is reported as a cumulative effect of a change in accounting principle. The Company recorded additional expense, net of income taxes, of approximately $0.8 million, or $0.02 per diluted common share reflecting the effect of changing the valuation date.

Year Ended December 31, 2002 Compared to Year Ended December 31, 2001

CONSOLIDATED

The Company's net earnings available to common shareholders for the year ended December 31, 2002 were $63.7 million, a 57.5% decrease in net earnings from $149.8 million in 2001. This decrease primarily reflected the slowdown in the wholesale electric market, where both prices and market liquidity were significantly lower than the prior year. Despite the slowdown in the wholesale electric market, PNM's electric utility operations recorded a gross margin growth of 4.5%. This growth came from a combination of load growth and utilization of lower cost generation demonstrating the balance that the regulated utility can provide in the Company's "merchant utility" strategy.

The following discussion is based on the methodology that the Company's management uses for making operating decisions and assessing performance of its various business activities. As such, these statements report operating results without regard to the effect of accounting or regulatory changes, and similar one-time items not related to normal operations. See Note 2 – "Segment Information" in the Notes to Consolidated Financial Statements for reconciliation between these results and the consolidated financial statements.

Corporate costs, income taxes and non-operating items are discussed only on a consolidated basis and are in conformity with the presentation in the consolidated financial statements.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

ELECTRIC

The table below sets forth the operating results for Electric (In thousands).

	YEAR ENDED DECEMBER 31,		
	2002	2001	VARIANCE
OPERATING REVENUES	$ 546,939	$ 532,673	$ 14,266
Less: Cost of energy	194,138	189,055	5,083
Energy transfer	(29,155)	(21,999)	(7,156)
GROSS MARGIN	381,956	365,617	16,339
Energy production costs	113,257	120,353	(7,096)
Distribution O&M	19,987	20,712	(725)
Customer related expense	17,372	19,388	(2,016)
Administrative and general	5,408	8,398	(2,990)
TOTAL NON-FUEL O&M	156,024	168,851	(12,827)
Corporate allocation	52,878	54,488	(1,610)
Depreciation and amortization	59,654	59,352	302
Taxes other than income taxes	18,251	16,272	1,979
Income taxes	26,779	13,788	12,991
Total non-fuel operating expenses	313,586	312,751	835
Operating income	$ 68,370	$ 52,866	$ 15,504

The following table shows electric revenues by customer class and average customers (In thousands):

ELECTRIC REVENUES	YEAR ENDED DECEMBER 31,		
	2002	2001	VARIANCE
Residential	$ 197,174	$ 187,600	$ 9,574
Commercial	247,800	242,372	5,428
Industrial	82,009	82,752	(743)
Other	19,956	19,949	7
	$ 546,939	$ 532,673	$ 14,266
AVERAGE CUSTOMERS	384,478	377,589	6,889

The following table shows electric sales by customer class (Megawatt hours):

ELECTRIC SALES	YEAR ENDED DECEMBER 31,		
	2002	2001	VARIANCE
Residential	2,298,542	2,197,889	100,653
Commercial	3,254,576	3,213,208	41,368
Industrial	1,612,723	1,603,266	9,457
Other	267,070	265,668	1,402
	7,432,911	7,280,031	152,880

Operating revenues increased $14.3 million or 2.7% for the period to $546.9 million. Retail electricity delivery grew 2.4% to 7.4 million MWh in 2002 compared to 7.3 million MWh delivered in the prior year, resulting in increased revenues of $14.3 million year-over-year. This volume increase was the result of a weather-driven increase in consumption and continued customer growth. Year over year, customer growth was 1.8%.

The gross margin, or operating revenues minus cost of energy sold, increased $16.3 million or 4.5%, which reflects the increased energy sales and the utilization of lower cost purchased power to serve jurisdictional needs based on a change in negotiated contract rates. Electric exclusively purchases transmission services from Transmission. These intercompany revenues and expenses are eliminated in the consolidated results.

Total non-fuel O&M decreased $12.8 million or 7.6%. Energy production costs decreased $7.1 million or 5.9% for the period reflecting the benefits of $2.0 million for the acceleration into 2001 of a planned outage at SJGS, decreased costs of $3.0 million for planned outages at SJGS and an adjustment of $3.1 million to prior year PVNGS billings from Arizona Public Service Company, the operator of PVNGS. These cost decreases were partially offset by costs of $1.2 million for planned and unplanned outages at Four Corners. Distribution costs decreased $0.7 million or 3.5% primarily due to maintenance performed in 2001 to improve system reliability, which did not recur in 2002. Customer related expense decreased $2.0 million or 10.4% due to lower bad debt expense as a result of collection improvements and the absence of losses from the bankruptcy of a significant customer in 2001. Administrative and other costs decreased $3.0 million or 35.6% due to an adjustment of $1.4 million to prior year SJGS participant billings and lower labor due to the transfer of employees from Electric to Corporate. Taxes other than income increased $2.0 million or 12.2% reflecting adjustments recorded in the prior year for favorable audit outcomes by certain tax authorities.

GAS

The table below sets forth the operating results for Gas (In thousands).

	YEAR ENDED DECEMBER 31,		
	2002	2001	VARIANCE
OPERATING REVENUES	$ 277,406	$ 371,265	$ (93,859)
Cost of energy	144,333	237,143	(92,810)
GROSS MARGIN	133,073	134,122	(1,049)
Energy production costs	1,937	1,946	(9)
Distribution O&M	29,306	31,064	(1,758)
Customer related expense	16,607	19,814	(3,207)
Administrative and general	2,943	6,736	(3,793)
TOTAL NON-FUEL O&M	50,793	59,560	(8,767)
Corporate allocation	33,516	30,908	2,608
Depreciation and amortization	20,673	20,362	311
Taxes other than income taxes	7,716	6,768	948
Income taxes	2,703	1,867	836
TOTAL NON-FUEL OPERATING EXPENSES	115,401	119,465	(4,064)
OPERATING INCOME	$ 17,672	$ 14,657	$ 3,015

The following table shows gas revenues by customer and average customers (In thousands):

GAS REVENUES	YEAR ENDED DECEMBER 31,		
	2002	2001	VARIANCE
Residential	$ 176,284	$ 221,409	$ (45,125)
Commercial	53,734	65,654	(11,920)
Industrial	2,872	27,519	(24,647)
Transportation*	17,735	20,188	(2,453)
Other	26,781	36,495	(9,714)
	$ 277,406	$ 371,265	$ (93,859)
AVERAGE CUSTOMERS	443,396	434,591	8,805

The following table shows gas throughput by customer class (Thousands of decatherms):

GAS THROUGHPUT	YEAR ENDED DECEMBER 31,		
	2002	2001	VARIANCE
Residential	29,627	27,848	1,779
Commercial	12,009	10,421	1,588
Industrial	749	3,920	(3,171)
Transportation*	44,889	51,395	(6,506)
Other	4,807	4,355	452
	92,081	97,939	(5,858)

*Customer owned gas

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Operating revenues decreased $93.9 million or 25.3% for the period to $277.4 million, primarily because of lower natural gas prices in 2002 as compared to 2001. PNM purchases natural gas in the open market and resells it at cost of purchase to its retail gas distribution customers. As a result, increases or decreases in gas revenues driven by gas costs do not impact the Company's consolidated gross margin or earnings.

The gross margin, or operating revenues minus cost of energy sold, decreased $1.0 million or 0.8%. This decrease is due mainly to lower consumption of gas for electric generation of $6.0 million partially offset by a 2.0% growth in customer base of $5.0 million.

Total non-fuel O&M decreased $8.8 million or 14.7%. Distribution costs decreased $1.8 million or 5.7% primarily due to maintenance performed in 2001 to improve system reliability, which did not recur in 2002. Customer related expense decreased $3.2 million or 16.2% due to lower bad debt expense because of collection improvements and the absence of losses from the bankruptcy of a significant customer in 2001. Administrative and other costs decreased $3.8 million due to lower amortization costs of $1.2 million for SFAS 106 deferred costs (which were fully amortized in 2001), and lower consulting expenses of $0.5 million in connection with cost control and process improvement initiatives in 2001 and lower legal expenses of $0.5 million for routine business matters. Taxes other than income taxes increased $0.9 million or 14.0% due to the absence of favorable audit outcomes by certain tax authorities recognized in 2001.

TRANSMISSION

The table below sets forth the operating results for Transmission (In thousands).

	YEAR ENDED DECEMBER 31,		
	2002	2001	VARIANCE
OPERATING REVENUES			
External customers	$ 23,150	$ 26,553	$ (3,403)
Intersegment revenues	31,950	31,273	677
TOTAL REVENUES	55,100	57,826	(2,726)
Cost of energy	3,888	5,102	(1,214)
GROSS MARGIN	51,212	52,724	(1,512)
Energy production costs	690	924	(234)
Transmission O&M	14,531	17,141	(2,610)
Customer related expense	9	–	9
Administrative and general	2,216	2,155	61
TOTAL NON-FUEL O&M	17,446	20,220	(2,774)
Corporate allocation	4,703	4,596	107
Depreciation and amortization	8,741	7,328	1,413
Taxes other than income taxes	2,464	2,252	212
Income taxes	4,699	5,442	(743)
TOTAL NON-FUEL OPERATING EXPENSES	38,053	39,838	(1,785)
OPERATING INCOME	$ 13,159	$ 12,886	$ 273

Operating revenues decreased $2.7 million or 4.7% and gross margin decreased $1.5 million or 2.9% primarily due to a decrease in third party sales of the Company's transmission capacity due to the slowdown in the wholesale market.

Total non-fuel O&M decreased $2.8 million or 13.7%. Transmission costs decreased $2.6 million or 15.2% primarily due to maintenance performed in 2001 to improve system reliability, which did not recur in 2002. Depreciation and amortization increased $1.4 million or 19.3% for the year due to the purchase of transmission plant assets in early 2002.

WHOLESALE

The table below sets forth the operating results for Wholesale (In thousands).

	YEAR ENDED DECEMBER 31,		
	2002	2001	VARIANCE
OPERATING REVENUES	$ 343,780	$ 1,411,500	$ (1,067,720)
Less: Cost of energy	262,517	1,127,970	(865,453)
Energy Transfer	29,155	21,999	7,156
GROSS MARGIN	52,108	261,531	(209,423)
Energy production costs	32,507	29,232	3,275
Transmission and distribution O&M	45	77	(32)
Customer related expense	754	821	(67)
Administrative and general	3,199	4,748	(1,549)
TOTAL NON-FUEL O&M	36,505	34,878	1,627
Corporate allocation	4,023	4,042	(19)
Depreciation and amortization	8,808	5,774	3,034
Taxes other than income taxes	2,619	2,498	121
Income taxes	(3,245)	78,102	(81,347)
TOTAL NON-FUEL OPERATING EXPENSES	48,710	125,294	(76,584)
OPERATING INCOME	$ 3,398	$ 136,237	$ (132,839)

The following table shows revenues by customer class (In thousands):

WHOLESALE REVENUES	YEAR ENDED DECEMBER 31,		
	2002	2001	VARIANCE
Long-term contracts	$ 58,546	$ 77,250	$ (18,704)
Forward sales	77,560	86,779	(9,219)
Short-term sales	207,674	1,247,471	(1,039,797)
	$ 343,780	$ 1,411,500	$ (1,067,720)

The following table shows sales by customer class (Megawatt hours):

WHOLESALE SALES	YEAR ENDED DECEMBER 31,		
	2002	2001	VARIANCE
Long-term contracts	844,169	1,463,031	(618,862)
Forward sales	1,336,745	537,665	799,080
Other merchant sales	7,269,240	10,596,004	(3,326,764)
	9,450,154	12,596,700	(3,146,546)

Operating revenues declined $1.1 billion or 75.6% for the year to $343.8 million. This decrease in wholesale electricity sales primarily reflects the slowdown in the wholesale electric market, which resulted from steep declines in wholesale prices and market liquidity as compared to the prior year period.

The significantly higher wholesale pricing in 2001 was driven by increased demand in California, a lack of generating assets to serve the market and the impact of warm weather. By contrast, 2002 saw relatively mild weather in the West, an abundance of low cost hydropower and weak economic conditions in the region. As a result, the average price realized by the Company fell to approximately $31 per MWh in 2002 versus $108 per MWh in 2001.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The decline in merchant sales volumes reflect the reduction in market participants in the wholesale market caused by bankruptcy, reduced credit quality of firms in the market and firms exiting the wholesale market. There are also significant unresolved legal, political and regulatory issues that had a dampening effect on activity in the marketplace. As a result, the Company's spot market and short-term sales declined significantly in 2002. The Company delivered wholesale (bulk) power of 9.5 million MWh of electricity for the year ended December 31, 2002, compared to 12.6 million MWh for the same period in 2001.

The gross margin, or operating revenues minus cost of energy sold, decreased $209.4 million or 80.1%. Lower margins were created primarily by weak pricing, less price volatility and lower market liquidity. In addition, unexpected outages at Four Corners reduced availability of power for wholesale sales. These lower margins were partially offset by a favorable change in the mark-to-market position of the marketing portfolio of $55.3 million year-over-year ($29.5 million gain in 2002 versus $25.8 million loss in 2001). A majority of the gain in 2002 represents the reversal of previously recognized mark-to-market losses.

Total non-fuel O&M increased $1.6 million or 4.7%. Energy production costs increased $3.3 million or 11.2% for the period due to costs of $4.0 million related to the future expansion of Afton. This cost increase was partially offset by decreased costs of $0.5 million for planned outages at SJGS. Depreciation and amortization expense increased $3.0 million or 52.5% for the period due to a higher depreciable plant base.

CORPORATE AND OTHER

Corporate administrative and general costs, which represent costs that are driven primarily by corporate-level activities, decreased $3.7 million or 4.0% for the period to $88.2 million. This decrease was due to lower bonus expense of $11.9 million in 2002 resulting from lower earnings projections. This decrease was partially offset by higher labor costs of $8.2 million resulting from a transfer of employees from operations to corporate.

CONSOLIDATED

Other Income and Deductions

Other income decreased by $3.8 million or 7.3% reflecting lower year-over-year returns on investments reflecting market conditions.

Other deductions decreased $55.0 million or 81.7% primarily due to charges in 2001 that did not recur in 2002. In 2001, the Company recognized charges for the write-off of an Avistar investment of $13.1 million, the write-off of non-recoverable coal mine decommissioning costs of $13.0 million, non-recoverable regulatory costs of $11.1 million, a contribution to the PNM Foundation of $5.0 million, and certain costs related to the Company's now terminated acquisition of Western Resources' electric utility operations of $18.0 million. In 2002, the Company recognized a gain from the reversal of a reserve of $2.4 million to reflect the early, successful resolution of the litigation stemming from the terminated Western Resources transaction and a charge of $4.8 million for the cancellation of a transmission line project.

Income Taxes

The Company's consolidated income tax expense was $33.0 million for the year ended December 31, 2002, compared to $81.1 million for the year ended December 31, 2001. The decrease was due to the impact of lower earnings and a decline in the effective tax rate. The Company's effective income tax rates for the years ended December 31, 2002 and 2001 were 33.95% and 35.02%, respectively. The decrease in the effective rate year over year was due to the reduction in earnings in 2002 without a corresponding reduction in permanent tax benefits and the recognition of certain affordable housing and research and development credits in 2002.

Critical Accounting Policies and Estimates

The preparation of financial statements in accordance with Generally Accepted Accounting Principles ("GAAP") requires management to select and apply accounting policies that best provide the framework to report the Company's results of operations and financial position. The selection and application of those policies require management to make difficult subjective or complex judgments concerning reported amounts of revenue and expenses during the reporting period and the reported amounts of assets and liabilities at the date of the financial statements. The judgments and uncertainties inherent in this process affect the application of those policies. As a result, there exists the likelihood that materially different amounts would be reported under different conditions or using different assumptions. Management has identified the following accounting policies that it deems critical to the portrayal of the Company's financial condition and results and that involve significant subjectivity. Management believes that its selection and application of these policies best represent the operating results and financial position of the Company. The following discussion provides information on the processes utilized by management in making judgments and assumptions as they apply to its critical accounting policies.

Revenue Recognition

Operating revenues are recorded as services are rendered to customers. The Company's Utility Operations records unbilled revenues representing the estimated amount customers will be billed for services rendered between the meter-reading dates in a particular month and the end of that month. The unbilled revenues estimate is reversed in the following month. To the extent the estimated amount differs from the amount subsequently billed, revenues will be affected. At December 31, 2003 and 2002, unbilled revenues in the consolidated balance sheet included estimates of $58.6 million and $58.5 million, respectively, from the Company's Utility Operations.

Regulatory Assets and Liabilities

The Company is subject to the provisions of Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation" ("SFAS No. 71"). Accordingly, the Company has recorded assets and liabilities on its balance sheet resulting from the effects of the ratemaking process, which would not be recorded under GAAP for non-regulated entities. Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent probable future reductions in revenue or refunds to customers. The Company's continued ability to meet the criteria for application of SFAS No. 71 may be affected in the future by competitive forces and restructuring in the electric industry. In the event that SFAS No. 71 no longer applied to all, or a separable portion, of Company's operations, the related regulatory assets and liabilities would be written off unless an appropriate regulatory recovery mechanism is provided.

Substantially all of the Company's regulatory assets and regulatory liabilities are reflected in rates charged to retail customers or have been addressed in a regulatory proceeding. To the extent that the Company concludes that the recovery of a regulatory asset is no longer probable due to regulatory treatment, the effects of competition or other factors, the amount would be recorded as a charge to earnings as recovery is no longer probable. The Company regularly assesses whether its regulatory assets are probable of future recovery by considering factors such as applicable regulatory environment changes, recent rate orders to other regulated entities in the same jurisdiction, anticipated future regulatory decisions and their impact, developments in the ratemaking process and the ability to recover costs.

As the Company's electric rates are fixed, the opportunity to recover increased costs and the costs of new investment in facilities through rates during the five-year rate freeze period is also limited. As a result, the Company defers certain costs based on its expectation that it will recover these costs in future rate cases. If future recovery of these costs ceases to be probable, the Company would be required to record a charge in current period earnings for the portion of the costs that were not recoverable.

Asset Impairment

The Company evaluates its tangible long-lived assets for impairment whenever indicators of impairment exist pursuant to Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of" ("SFAS 144"). These potential impairment triggers would include fluctuating market conditions as a result of industry deregulation; planned and scheduled customer purchase commitments; future market penetration; fluctuating market prices (resulting from changing fuel costs, other economic conditions, etc.); weather patterns, and other market trends. Accounting rules require that if the sum of the undiscounted expected future cash flows from a company's asset (without interest charges that will be recognized as expenses when incurred), is less than the carrying value of the asset, an asset impairment must be recognized in the financial statements. The amount of impairment recognized is the difference between the fair value of the asset and the carrying value of the asset.

The Company determined that no triggering events occurred during the period in regards to its generation assets. At December 31, 2003, the Company analyzed three turbines, which are currently in storage, with a combined carrying value of approximately $79.1 million. These assets were intended for planned build-outs that have been delayed or canceled. Based on the Company's various plans to make these turbines operational, the Company concluded that it will fully recover its investment. The Company expects to begin construction utilizing these assets over the next several years. If the Company were unable to realize these plans, the Company would be forced to recognize a loss with respect to the carrying value of these assets depending on prevailing market conditions. The Company will continue to analyze the turbines for impairment in accordance with SFAS 144.

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Pension Plan

The Company and its subsidiaries maintain a qualified defined benefit pension plan ("pension plan"), which covers eligible non-union and union employees including officers. The pension plan was frozen at the end of 1997 with regard to new participants, salary levels and benefits. The Company's policy is to fund actuarially-determined contributions.

The Company's expense for its pension plan approximated $2.4 million for the year ended December 31, 2003, and is calculated based upon a number of actuarial assumptions, including an expected long-term rate of return on the pension plan assets of 9%. In developing the expected long-term rate of return assumption, the Company evaluated input from its actuaries and its investment consultant, including their review of asset class return expectations as well as long-term inflation assumptions. This long-term rate of return assumption compares to the historical 10-year compounded return of 9.86% through the end of December 2003. The expected long-term rate of return on the pension plan assets is based on an asset allocation assumption of 58% with equity managers, 22% with fixed income managers, and 20% with alternative investments that are primarily real estate, private equity, and absolute return strategies. The pension plan's actual asset allocation as of December 31, 2003 was 65% with equity managers, 25% with fixed income managers, and 10% with alternative investments. The Company reviews the actual asset allocation and periodically rebalances the asset allocation to the targeted allocation. The Company continues to believe that 9% is a reasonable long-term rate of return on the pension plan's assets, despite the recent market upturn in which the pension plan assets had a gain of 21.0% for the twelve months ended December 31, 2003. The Company will continue to evaluate its actuarial assumptions, including expected rate of return, at least annually, and will adjust as necessary.

The Company bases its determination of pension expense or income on a market-related valuation of assets, which reduces year-to-year volatility. If investment return is outside a range of 5% to 13% (expected long-term rate of return plus or minus 4%), this market-related valuation recognizes the portion of return that is outside the range over a five-year period from the year in which the return occurs. Since the market-related value of assets recognizes the portion of return that is outside the range over a five-year period, the future value of assets will be impacted as previously deferred returns are recorded.

The discount rate that the Company utilizes for determining future pension obligations is based on a review of long-term high-grade bonds and management's expectation. As a result of this review, the Company adjusted the rate to 6.5% at December 31, 2003 from 6.75% at September 30, 2002. Based on an expected rate of return on the pension plan assets of 9%, a discount rate of 6.5% and various other assumptions, it is estimated that the pension income for the pension plan will approximate $0.7 million in fiscal year 2004 and $1.4 million in fiscal year 2005. Future actual pension income or expense will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the Company's pension plans.

Lowering the pension plan's expected long-term rate of return on pension assets by 0.5% (from 9% to 8.5%) would have raised pension expense for fiscal year 2003 by approximately $1.8 million. Lowering the discount rate by 0.5% would have increased pension expense for fiscal year 2003 by approximately $2.6 million.

The value of the pension plan assets has increased from $326.5 million at December 31, 2002 to $425.7 million at December 31, 2003 including $48.9 million of contributions during 2003. The Company does not expect to make any contributions for the 2004 plan year.

Self-Insurance

The Company self-insures for certain losses related to general liability, workers' compensation and automobile claims. The Company maintains insurance with third-party insurers in excess of the Company's self-insured retentions to limit the Company's exposure per occurrence or accident, as applicable. The Company's self-insurance liabilities reflect the estimated ultimate cost of claims incurred as of the balance sheet date. The estimated liabilities are not discounted and are established based upon claims filed, estimated claims incurred but not reported, and analyses of industry and historical data.

Beginning January 1, 2004, the Company began to self-insure certain health care costs of its employees. The Company self-insures for certain medical and dental benefits for active employees and retirees under the benefit programs. The Company maintains stop-loss insurance with third-party insurers in excess of the Company's self-insured retentions to limit the Company's exposure per participant, as applicable.

Management reviews the amounts recorded for these liabilities on a quarterly basis to ensure that they are appropriate. While management believes that these estimates are reasonable based on the information available, the Company's financial results could be impacted if actual trends, including the severity or frequency of claims or fluctuations in premiums, differ from the Company's estimates.

Contingent Liabilities

There are various claims and lawsuits pending against the Company and certain of its subsidiaries. The Company has recorded a liability when the effect of litigation can be estimated and where an outcome is considered probable. Management's estimates are based on its knowledge of the relevant facts at the time of the issuance of the Company's consolidated financial statements. Subsequent developments could materially alter management's assessment of a matter's probable outcome and the estimate of liability.

Environmental Issues

The Company records its environmental liabilities when site assessments or remedial actions are probable and a range of reasonably likely cleanup costs can be estimated. The Company 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, current 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, the Company records the lower end of this reasonably likely range of costs (classified as other long-term liabilities at undiscounted amounts). Subsequent developments could materially alter management's assessment of a matter's probable outcome and the estimate of liability.

See "Item 7A. Quantitative and Qualitative Disclosure About Market Risk – Interest Rate Risk" for discussion regarding the Company's accounting policies and sensitivity analysis for the Company's financial instruments and derivative energy and other derivative contracts. See also "Financing Activities" below for additional discussion regarding the Company's accounting policies for forward interest swaps.

Effects of Certain Events on Future Revenues

The Company's long-term contracts to supply power expire from 2006 through 2013. The ability of the Company to renew these contracts at terms comparable to those currently in place is dependent upon prevailing market conditions at the time of negotiations. Currently, the Company has a long-term firm commitment contract of 114 MW set to expire in 2006. The contract is priced significantly above current market prices; however, the Company believes that it will be able to significantly mitigate any revenue loss due to a rising forward market.

Liquidity and Capital Resources

At December 31, 2003, the Company had cash and short-term investments of $12.7 million compared to $83.3 million in cash and short-term investments at December 31, 2002.

Cash provided by operating activities for the year ended December 31, 2003 was $228.7 million compared to $97.4 million for the year ended December 31, 2002. This increase in cash flows was due to increased profitability in the Company's wholesale power operations, higher gas sales volumes and lower tax payments. Also contributing to the increase were payments in 2002 which did not recur in 2003. The Company did not make its first quarter 2001 estimated federal income tax payment of $32.0 million until January 2002 because of an extension granted by the IRS to taxpayers in several counties in New Mexico as a result of wildfires in 2000. In addition, the Company made payments in 2002 of $36.0 million for the termination of the surface coal contract and $23.2 million to secure a long-term wholesale contract. This increase in operating cash flows was offset by higher wholesale electric prices and volume and higher gas prices in the current year. The Company's Gas working capital is negatively affected by the timing difference in gas purchases and collections. The Company pays for gas in the month following purchase. Recovery of gas costs has typically taken up to three months. The negative effect of this mismatch in cash flows was greater in 2003 due to the increase in gas prices. The increase in accounts receivable also reflects higher wholesale electric prices in 2003. In addition, electric retail collections decreased due to the rate reduction.

Cash used for investing activities was $101.6 million in 2003 compared to $200.4 million in 2002. Cash used in 2002 for investing activities included construction expenditures for new generating plants of $67.4 million. Payments for combustion turbines were $11.1 million in 2003 compared to $30.0 million in 2002. Cash used for investing activities in 2003 also included the purchase of certain long-term debt underlying leased assets in the open market for $6.7 million (see "Liquidity" below). The cash used for investing activities in 2003 was largely offset by the redemption of short-term investments of $80.3 million in 2003 at the Holding Company level as compared to $45.6 million in 2002 at PNM. These redemptions were primarily used for the Company's retirement of the EIP long-term debt underlying the lease assets, repayment of short-term debt, debt refinancing and pension funding.

Cash used for financing activities was $118.1 million in 2003 compared to cash generated by financing activities of $78.4 million in 2002. Financing activities in 2003 primarily consisted of the retirement of long-term debt of $26.1 million, costs associated with the refunding and refinancing of long-term debt of $55.3 million and short-term debt repayments of $24.1 million. In 2002, the Company had short-term borrowings of $115.0 million for short-term liquidity needs.

Pension and Other Post-Retirement Benefits

In May 2003, the board of directors approved the use of Holding Company stock in the funding of the Company's pension plan as well as its retiree medical trust. Corporate plan sponsors may make contributions of common stock to their defined benefit plans of up to 10% of the value of the portfolio without Department of Labor ("DOL") approval, provided that the contribution does not otherwise constitute a prohibited transaction under the Employee Retirement Income Security Act ("ERISA"). In June 2003, a contribution of 1,121,495 shares of Holding Company common stock (approximately $28.9 million in market value) was made to the Company's pension plan. The shares of Holding Company common stock were sold over a period of time and there were no shares of common stock remaining in the defined benefit trust on December 31, 2003. Due to the appreciation in stock value, the net proceeds realized by the pension plan from the sale of Holding Company common stock was $31.0 million.

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Capital Requirements

Total capital requirements include construction expenditures as well as other major capital requirements and cash dividend requirements for both common and preferred stock. The main focus of the Company's current construction program is upgrading generation systems, upgrading and expanding the electric and gas transmission and distribution systems and purchasing nuclear fuel. To preserve a strong financial position, the Company announced in 2002 its plans to delay capital expenditures for previously planned generation expansion. Projections for total capital requirements for 2004 are $172 million and projections for construction expenditures for 2004 are $154 million. Total capital requirements are projected to be $720 million and construction expenditures are projected to be $624 million for 2004-2008. These estimates are under continuing review and subject to on-going adjustment. This projection excludes any generation fleet expansion capital, including any plans for the utilization of the turbines in storage. The Company continues to look for appropriately priced generation acquisition and expansion opportunities to support retail electric load growth, the continued expansion of its long-term contract business and to supplement its natural transmission position in the Southwest and West.

In the year ended December 31, 2003, the Company utilized cash generated from operations and cash on hand, as well as its liquidity arrangements, to cover its capital requirements and construction expenditures. The Company anticipates that internal cash generation and current debt capacity will be sufficient to meet all of its capital requirements and construction expenditures for the years 2004 through 2008. To cover the difference in the amounts and timing of cash generation and cash requirements, the Company intends to use short-term borrowings under its current and future liquidity arrangements.

Liquidity

As of March 1, 2004, PNM had $413.0 million of liquidity arrangements. The liquidity arrangements consist of $300.0 million from an unsecured revolving credit facility ("Credit Facility"), $90.0 million from an accounts receivable securitization program ("AR Securitization") and $23.0 million in local lines of credit. PNM entered into a new revolving credit facility on November 21, 2003, which increased borrowing capacity from $195.0 million to $300.0 million. This facility will mature November 21, 2006. As of March 1, 2004, there were no borrowings against the Credit Facility, PNM was using $60.0 million of the AR Securitization capacity and no borrowings under its local lines of credit. PNM had $50.0 million of commercial paper outstanding as of March 1, 2004. In addition, the Holding Company has $15.0 million in local lines of credit with no usage at December 31, 2003 or March 1, 2004.

On April 8, 2003, the Company entered into the AR Securitization providing for the securitization of PNM's retail electric service accounts receivable and retail gas services accounts receivable. The total capacity under the AR Securitization is $90.0 million. Under the AR Securitization, PNM will periodically sell its accounts receivable, principally retail receivables, to a bankruptcy remote subsidiary, PNM Receivables Corp, which in turn pledges an undivided interest in the receivables to an unaffiliated conduit commercial paper issuer.

On April 1, 2003, PNM exercised its early buyout option related to a 60% interest in the EIP transmission line and related facilities held under lease. Through the exercise of the early buyout option, PNM was able to retire all $26.2 million of secured facility bonds, which were issued to originally finance the sale-leaseback transaction. The secured facility bonds had previously been disclosed as off balance sheet lease obligations in the notes to the Company's financial statements. The Company will continue to exclude approximately $4.0 million of lease obligations relating to the 40% interest the Company does not own from the consolidated balance sheet.

On June 12, 2003, the Holding Company and PNM each filed universal shelf registration statements with the SEC for a combination of debt and equity securities for $500.0 million and $285.0 million, respectively. The PNM shelf registration statement when combined with a previously filed shelf registration statement, provides $500.0 million of capacity. The PNM and Holding Company shelf registration statements were declared effective June 28, 2003 and August 28, 2003, respectively. On September 9, 2003, PNM issued and sold $300.0 million of debt under its shelf registration statement (see "Financing Activities" below). As of December 31, 2003, the Holding Company and PNM had remaining unissued securities registered under the shelf registration statements of $500.0 million and $200.0 million, respectively.

On August 27, 2003, the Company entered into an unrated private issuance commercial paper program. The Company will periodically issue up to $50.0 million in unrated commercial paper for the shorter of 120 days or the maturity of the Company's Credit Facility. The commercial paper is unsecured and the proceeds will be used to reduce revolving credit borrowings. The Company's Credit Facility serves as a backstop for the outstanding commercial paper.

The Company's ability to access the capital markets, if required, at a reasonable cost and to provide for other capital needs is largely dependent upon its ability to earn a fair return on equity, its results of operations, its credit ratings, obtaining required regulatory approvals and financial and wholesale market conditions. Financing flexibility is enhanced by providing a high percentage of total capital requirements from internal sources and having the ability, if necessary, to issue long-term securities and to obtain short-term credit.

PNM's credit outlook is considered stable by Moody's Investor Services, Inc. ("Moody's") and Standard and Poor's Ratings Services ("S&P"). The Company is committed to maintaining or improving its investment grade ratings. On June 13, 2003, S&P improved PNM's business position to a five from its previous position of six. On February 27, 2004, S&P upgraded PNM's ratings on its senior unsecured notes ("SUNs") to "BBB" with a stable outlook and its preferred stock to "BB+". On March 9, 2004, Moody's upgraded PNM's SUNs, senior unsecured pollution control revenue bonds and $300 million 3 year credit facility to "Baa2" and its preferred stock "Ba1". Fitch rated PNM's SUNs and senior unsecured pollution control revenue bonds "BBB-" and its preferred stock "BB-" at December 31, 2003. Beginning in 2004, Fitch will no longer be rating PNM debt. Investors are cautioned that a security rating is not a recommendation to buy, sell or hold securities, that it is subject to revision or withdrawal at any time by the assigning rating organization, and that each rating should be evaluated independently of any other rating.

Off Balance Sheet Arrangements

The Company's off balance sheet arrangements consist primarily of operating lease obligations for PVNGS Units 1 and 2, EIP and the Delta operating lease. The total capitalization in relation to these obligations was $179.4 million as of December 31, 2003 and $195.8 million as of December 31, 2002 (see "Commitments and Contractual Obligations" below).

Commitments and Contractual Obligations

The following tables show the Company's long-term obligations and commitments as of December 31, 2003 (In thousands).

	PAYMENTS DUE				
CONTRACTUAL OBLIGATIONS	TOTAL	LESS THAN 1 YEAR	2-3 YEARS	4-5 YEARS	AFTER 5 YEARS
Short-Term Debt (a)	$ 125,918	$ 125,918	$ –	$ –	$ –
Long-Term Debt	987,210	407	814	300,170	685,819
Operating Leases	425,540	29,068	62,266	65,796	268,410
Purchased Power Agreements	203,282	27,733	50,870	35,233	89,446
Coal Contract (b)	1,395,926	109,309	192,456	182,359	911,802
Total Contractual Cash Obligations	$ 3,137,876	$ 292,435	$ 306,406	$ 583,558	$1,955,477

(a) Represents the actual outstanding balance of the various credit facilities as of December 31, 2003.

(b) Assumes normal deliveries under the coal contract. If no deliveries are made, certain minimum payments may be required under the coal contract.

	AMOUNT OF COMMITMENT EXPIRATION PER PERIOD				
OTHER COMMERCIAL COMMITMENTS	TOTAL AMOUNTS COMMITTED	1 YEAR	2-3 YEARS	4-5 YEARS	AFTER 5 YEARS
Short-Term Debt (c)	$ 335,500	$ –	$ 335,500	$ –	$ –
Local Lines of Credit	38,500	38,500	–	–	–
Letters of Credit	4,500	4,500	–	–	–
Total Commercial Commitments	$ 378,500	$ 43,000	$ 335,500	$ –	$ –

(c) Represents the unused borrowing capacity of the various credit facilities less outstanding letters of credit of $4.5 million as of December 31, 2003.

PNM leases interests in Units 1 and 2 of PVNGS, certain transmission facilities, office buildings and other equipment under operating leases. The lease expense for PVNGS is $66.3 million per year over base lease terms expiring in 2015 and 2016. In 1998, PNM established PVNGS Capital Trust ("Capital Trust") for the purpose of acquiring all the debt underlying the PVNGS leases. PNM consolidates Capital Trust in its consolidated financial statements. The purchase was funded with the proceeds from the issuance of $435 million of SUNs, which were loaned to Capital Trust. Capital Trust then acquired and now holds the debt component of the PVNGS leases. For legal and regulatory reasons, the PVNGS lease payment continues to be recorded and paid gross with the debt component of the payment returned to PNM through Capital Trust. As a result, the net cash outflows for the PVNGS lease payment were $14.2 million for the year ended December 31, 2003. The table above reflects the net lease payment.

PNM's other significant operating lease obligations include the EIP, a leased interest in transmission line with annual lease payments of $2.9 million (see "Financing Activities" below), and an operating lease for the entire output of Delta, a gas fired generating plant in Albuquerque, New Mexico, with imputed annual lease payments of $6.0 million.

The Company's off-balance sheet obligations are limited to PNM's operating leases and certain financial instruments related to the purchase and sale of energy (see below). The present value of PNM's operating lease obligations for PVNGS Units 1 and 2, EIP and the Delta operating lease was $179.4 million as of December 31, 2003.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

PNM has entered into various long-term power purchase agreements ("PPAs") obligating it to buy electricity for aggregate fixed payments of $203.3 million plus the cost of production and a return. These contracts expire December 2005 through December 2020. In addition, PNM is obligated to sell electricity for $191.5 million in fixed payments plus the cost of production and a return. These contracts expire through May 2013. PNM's marketing portfolio as of December 31, 2003 included open forward contract positions to buy $30.6 million of electricity and to sell $28.6 million of electricity. In addition, PNM had open forward contract positions classified as normal sales of electricity under the derivative accounting rules of $153.3 million and normal purchases of electricity of $64.1 million.

PNM contracts for the purchase of gas to serve its retail customers. These contracts are short-term in nature, supplying the gas needs for the current heating season and the following off-season months. The price of gas is a pass-through, whereby PNM recovers 100% of its cost of gas.

Contingent Provisions of Certain Obligations

The Holding Company and PNM have a number of debt obligations and other contractual commitments that contain contingent provisions. Some of these, if triggered, could affect the liquidity of the Company. The Holding Company or PNM could be required to provide security, immediately pay outstanding obligations or be prevented from drawing on unused capacity under certain credit agreements if the contingent requirements were to be triggered. The most significant consequences resulting from these contingent requirements are detailed in the discussion below.

PNM's master purchase agreement for the procurement of gas for its retail customers contains a contingent requirement that could require PNM to provide security for its gas purchase obligations if the seller were to reasonably believe that PNM was unable to fulfill its payment obligations under the agreement.

The master agreement for the sale of electricity in the Western Systems Power Pool ("WSPP") contains a contingent requirement that could require PNM to provide security if its debt were to fall below investment grade rating. The WSPP agreement also contains a contingent requirement, commonly called a material adverse change ("MAC") provision, which could require PNM to provide security if a material adverse change in its financial condition or operations were to occur.

PNM's committed Credit Facility contains a "ratings trigger," for pricing purposes only. If PNM is downgraded or upgraded by the ratings agencies, the result would be an increase or decrease in interest cost, respectively. PNM's committed Credit Facility contains a MAC provision which, if triggered, could prevent PNM from drawing on its unused capacity under the Credit Facility. In addition, the Credit Facility contains a contingent requirement that requires PNM to maintain a debt-to-capital ratio, inclusive of off-balance sheet debt, of less than 65% as well as maintenance of an earnings before interest, taxes, depreciation and amortization ("EBITDA")/interest coverage ratio of three times. If PNM's debt-to-capital ratio, inclusive of off-balance sheet debt, were to exceed 65% or its interest coverage ratio falls below 3.0, PNM could be required to repay all borrowings under the Credit Facility, be prevented from drawing on the unused capacity under the Credit Facility, and be required to provide security for all outstanding letters of credit issued under the Credit Facility.

If a contingent requirement were to be triggered under the Credit Facility resulting in an acceleration of the outstanding loans under the Credit Facility, a cross-default provision in the PVNGS leases could occur if the accelerated amount is not paid. If a cross-default provision is triggered, the lessors have the ability to accelerate their rights under the leases, including acceleration of all future lease payments.

Financing Activities

Pursuant to PRC approval, on September 9, 2003, PNM issued and sold $300.0 million aggregate principal amount of its senior unsecured notes with a 4.40% interest rate that mature September 15, 2008. The transaction closed on September 17, 2003 and the proceeds were used to retire $268.4 million of long-term debt that would otherwise have matured in August 2005, pay the transaction costs, and improve working capital. All other long-term debt of PNM matures in 2016 or later. The premium paid to refinance the long-term debt was $23.9 million of which $16.6 million was charged against earnings based on prior regulatory agreements. The remaining balance was capitalized as loss on reacquired debt and will be amortized over the life of the new debt.

On May 13, 2003, the Company priced $182.0 million of tax exempt pollution control bonds. The bonds were priced at an initial interest rate of 2.75%. The bond sale closed on May 23, 2003. By April 1, 2004, $146.0 million of bonds will need to be remarketed and $36.0 million of bonds will need to be remarketed by July 1, 2004. A portion of the proceeds were used to redeem the $46.0 million of pollution control bonds, which became callable on December 15, 2002. The remaining $136.0 million was used to redeem $136.0 million of pollution control bonds in August 2003. The Company had previously entered into various forward swaps in 2001 and 2002, to hedge the interest rate on the refinancing (see Note 6 – "Fair Value of Financial Instruments - Forward Starting Interest Rate Swaps" in the Notes to Consolidated Financial Statements).

The Company could enter into other long-term financings or hedging transactions for the purpose of strengthening its balance sheet, funding growth and reducing its cost of capital. The Company continues to evaluate its investment and debt retirement options to optimize its financing strategy and earnings potential. No additional first mortgage bonds may be issued under PNM's mortgage. The amount of SUNs that may be issued is not limited by the SUNs indenture. However, debt-to-capital requirements in certain of PNM's financial instruments and regulatory agreements would ultimately limit the amount of additional debt PNM would issue.

Dividends

The Holding Company's board of directors regularly reviews the dividend policy. The declaration of common dividends is dependent upon a number of factors including the ability of the Holding Company's subsidiaries to pay dividends. Currently, PNM is the Holding Company's primary source of dividends. As part of the order approving the formation of the Holding Company, the PRC placed certain restrictions on the ability of PNM to pay dividends to the Holding Company. PNM cannot pay dividends that will cause its debt rating to go below investment grade. PNM also cannot pay dividends in any year, as determined on a rolling four-quarter basis, in excess of net earnings for that year without prior PRC approval. PNM has dividended all eligible amounts under the pre-2003 agreement to its parent. In January 2003, with the signing of the Global Electric Agreement, the PRC modified the PNM dividend restriction to allow PNM to dividend earnings as well as equity contributions made by the Holding Company back to the Holding Company. Additionally, PNM has various financial covenants, which limit the transfer of assets, whether through dividends or other means.

In addition, the ability of the Holding Company to declare dividends is dependent upon the extent to which cash flows will support dividends, the availability of earnings, its financial circumstances and performance, the effect of regulatory decisions and legislative activities, future growth plans, the related capital requirements, standard business considerations and market and economic conditions generally.

Consistent with the PRC's holding company order, PNM paid dividends of $49.6 million to the Holding Company for the year ended December 31, 2003.

On February 17, 2004, the Holding Company's board of directors approved a 4.3% increase in the common stock dividend. The increase raised the quarterly dividend to $0.24 per share, for an indicated annual dividend of $0.96 per share.

Capital Structure

The Company's capitalization, including current maturities of long-term debt, is shown below:

	DECEMBER 31,	
	2003	2002
Common Equity	51.9%	49.5%
Preferred Stock	0.6%	0.7%
Long-term Debt	47.5%	49.8%
Total Capitalization*	100.0%	100.0%

* Total capitalization does not include as debt the present value of PNM's operating lease obligations for PVNGS Units 1 and 2, EIP and the Delta operating lease which was $179.4 million as of December 31, 2003 and $195.8 million as of December 31, 2002.

Other Issues Facing the Company

See Note 13 – "Commitments and Contingencies" in the Notes to Consolidated Financial Statements.

New and Proposed Accounting Standards

See Note 18 – "New and Proposed Accounting Standards" in the Notes to Consolidated Financial Statements.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Quantitative and Qualitative Disclosure About Market Risk

The Company uses derivative financial instruments to manage risk as it relates to changes in natural gas and electric prices, changes in interest rates and, historically, adverse market changes for investments held by the Company's various trusts. Additionally, the Company uses derivative instruments based on certain financial composite indices as part of its enhanced cash management program. The Company also uses certain derivative instruments for wholesale power marketing transactions in order to take advantage of favorable price movements and market timing activities in the wholesale power markets. The following additional information is provided.

Risk Management

The Company controls the scope of its various forms of risk through a comprehensive set of policies and procedures and oversight by senior level management and the Holding Company Board of Directors. The Board's Finance Committee sets the risk limit parameters. The Risk Management Committee ("RMC"), comprised of corporate and business segment officers and other managers, oversees all of the activities, which include commodity price, credit, equity, interest rate and business risks. The RMC has oversight for the ongoing evaluation of the adequacy of the risk control organization and policies. The Company has a risk control organization, headed by the Director of Financial Risk Management ("Risk Manager"), which is assigned responsibility for establishing and enforcing the policies, procedures and limits and evaluating the risks inherent in proposed transactions, on an enterprise-wide basis.

The RMC's responsibilities specifically include: establishment of a general policy regarding risk exposure levels and activities in each of the business segments; recommendation of the types of instruments permitted; authority to establish a general policy regarding counterparty exposure and limits; authorization and delegation of transaction limits; review and approval of controls and procedures; review and approval of models and assumptions used to calculate mark-to-market and risk exposure; authority to approve and open brokerage and counterparty accounts; review of hedging and risk activities; and quarterly reporting to the Finance Committee and the Board of Directors on these activities.

The RMC also proposes Value at Risk ("VAR") limits to the Finance Committee. The Finance Committee ultimately sets the aggregate VAR limits.

It is the responsibility of each business segment to create its own control procedures and policies within the parameters established by the Finance Committee. The RMC reviews and approves these policies, which are created with the assistance of the Corporate Controller, Director of Internal Audit and the Risk Manager. Each business segment's policies address the following controls: authorized risk exposure limits; authorized instruments and markets; authorized personnel; policies on segregation of duties; policies on mark-to-market accounting; responsibilities for deal capture; confirmation procedures; responsibilities for reporting results; statement on the role of derivative transactions; and limits on individual transaction size (nominal value).

To the extent an open position exists, fluctuating commodity prices can impact financial results and financial position, either favorably or unfavorably. As a result, the Company cannot predict with certainty the impact that its risk management decisions may have on its businesses, operating results or financial position.

Commodity Risk

Marketing and procurement of energy often involves market risks associated with managing energy commodities and establishing open positions in the energy markets, primarily on a short-term basis. These risks fall into three different categories: price and volume volatility, credit risk of counterparties and adequacy of the control environment. PNM routinely enters into forward contracts and options to hedge purchase and sale commitments, fuel requirements and to enhance returns and minimize the risk of market fluctuations on the Wholesale Operations.

The Company's Wholesale Operations, including long-term contracts, forward sales and short-term sales, are managed through a net asset-backed marketing strategy, whereby PNM's aggregate net open forward contract position is covered by its forecasted excess generation capabilities. PNM is exposed to market risk if its generation capabilities were disrupted or if its retail load requirements were greater than anticipated. If PNM were required to cover all or a portion of its net open contract position, it would have to meet its commitments through market purchases.

Under the derivative accounting rules and the related accounting rules for energy contracts, the Company accounts for its various financial derivative instruments for the purchase and sale of energy differently based on management's intent when entering into the contract. Energy contracts which meet the definition of a derivative under SFAS 133 and do not qualify for a normal purchase or sale designation are recorded on the balance sheet at fair market value at each period end. The changes in fair market value are recognized in earnings unless specific hedge accounting criteria are met. Should an energy transaction qualify as a hedge under SFAS 133, fair market value changes from year to year are recognized on the balance sheet with a corresponding charge to other comprehensive income. Gains or losses are recognized when the hedged transaction settles. Derivatives that meet the normal sales and purchases exceptions within SFAS 133 as amended, are not marked to market but rather recorded in results of operations when the underlying transaction settles.

The following table shows the net fair value of mark-to-market energy contracts included in the balance sheet (In thousands):

	DECEMBER 31,	
	2003	2002
Mark-to-Market Energy Contracts:		
Current asset	$ 2,098	$ 4,531
Long-term asset	1,359	267
TOTAL MARK-TO-MARKET ASSETS	**3,457**	**4,798**
Current liability	(1,941)	(5,725)
Long-term liability	(1,083)	-
TOTAL MARK-TO-MARKET LIABILITIES	**(3,024)**	(5,725)
NET FAIR VALUE OF MARK-TO-MARKET ENERGY CONTRACTS	**$ 433**	**$ (927)**

The mark-to-market energy portfolio positions represent net assets at December 31, 2003 and represent net liabilities at December 31, 2002 after netting all applicable open purchase and sale contracts.

The market prices used to value PNM's mark-to-market energy portfolio are based on closing exchange prices and broker quotations. As of December 31, 2003 and December 31, 2002, PNM did not have any outstanding contracts that were valued using methods other than quoted prices. The Company did not change its methods for valuing its mark-to-market energy portfolio in 2003 as compared to 2002.

The following table provides detail of changes in the Company's mark-to-market energy portfolio net asset or liability balance sheet position from one period to the next (In thousands):

	TWELVE MONTHS ENDED DECEMBER 31,	
	2003	2002
Sources of Fair Value Gain/(Loss)		
Fair value at beginning of year	$ (927)	$ (30,440)
Amount realized on contracts delivered during period	(2,113)	26,336
Changes in fair value	3,473	3,177
NET FAIR VALUE AT END OF PERIOD	**$ 433**	**$ (927)**
NET CHANGE RECORDED AS MARK-TO-MARKET	**$ 1,360**	**$ 29,513**

The following table provides the maturity of the net assets/(liabilities) of the Company, giving an indication of when these mark-to-market amounts will settle and generate/(use) cash. The following values were determined using broker quotes (In thousands):

	FAIR VALUE AT DECEMBER 31, 2003		
	LESS THAN 1 YEAR	1-3 YEARS	TOTAL
Maturities	$ 157	$ 276	$ 433

As of December 31, 2003, a decrease in market pricing of PNM's mark-to-market energy portfolio by 10% would have resulted in a decrease in net earnings of less than 1%. Conversely, an increase in market pricing of this portfolio by 10% would have resulted in an increase in net earnings of less than 1%.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The Company assesses the risk of these long-term contracts and wholesale sales activities using the VAR method to maintain the Company's total exposure within management-prescribed limits. The Company utilizes the variance/covariance model of VAR, which is a probabilistic model that measures the risk of loss to earnings in market sensitive instruments. The variance/covariance model relies on statistical relationships to analyze how changes in different markets can affect a portfolio of instruments with different characteristics and market exposure. VAR models are relatively sophisticated. The quantitative risk information, however, is limited by the parameters established in creating the model. The instruments being evaluated may trigger a potential loss in excess of calculated amounts if changes in commodity prices exceed the confidence level of the model used. The VAR methodology employs the following critical parameters: volatility estimates, market values of open positions, appropriate market-oriented holding periods and seasonally adjusted correlation estimates. The Company's portfolio VAR calculation considers the Company's forward position for the preceding eighteen months. The mark-to-market VAR is calculated through the contract periods. The Company uses a holding period of three days as the estimate of the length of time that will be needed to liquidate the positions. The volatility and the correlation estimates measure the impact of adverse price movements both at an individual position level as well as at the total portfolio level. The two-tailed confidence level established is 99%. For example, if VAR is calculated at $10.0 million, it is estimated at a 99% confidence level that if prices move against PNM's positions, the Company's pre-tax gain or loss in liquidating the portfolio would not exceed $10.0 million in the three days that it would take to liquidate the portfolio.

The Company's VAR is regularly monitored by the Company's RMC. The RMC has put in place procedures to ensure that increases in VAR are reviewed and, if deemed necessary, acted upon to reduce exposures. The VAR represents an estimate of the potential gains or losses that could be recognized on PNM's wholesale power marketing portfolios given current volatility in the market, and is not necessarily indicative of actual results that may occur, since actual future gains and losses will differ from those estimated. Actual gains and losses may differ due to actual fluctuations in market rates, operating exposures, and the timing thereof, as well as changes to PNM's wholesale power marketing portfolios during the year.

The Company accounts for the sale of electric generation in excess of its retail needs or the purchase of power for retail needs as normal purchases and sales under SFAS 133. Transactions that do not meet the normal purchase or sale exception or the definition of a hedge under SFAS 133 are accounted for as energy marketing contracts and comprise PNM's mark-to-market portfolio. The VAR for the mark-to-market portfolio was $56 thousand at December 31, 2003. The Company also calculates a portfolio VAR for the preceding 18 months, which in addition to its mark-to-market portfolio includes all contracts designated as normal sales and purchases, hedges, and its estimated excess generation assets. This excess is determined using average peak forecasts for the respective block of power in the forward market. The Company's portfolio VAR was $9.2 million at December 31, 2003.

The following table shows the high, average and low market risk as measured by VAR on the Company's mark-to-market portfolio (In thousands):

	TWELVE MONTHS ENDED DECEMBER 31, 2003			
	HIGH	AVERAGE	LOW	PERIOD END
Three day holding period, 99% two-tailed confidence level	$ [illegible]	$ 122	$ 1	$ 56
One day holding period, 99% two-tailed confidence level	$ 420	$ 70	$ –	$ 32
Ten day holding period, 95% two-tailed confidence level	$ [illegible]	$ 170	$ 1	$ 78

Credit Risk

PNM is exposed to credit losses in the event of non-performance or non-payment by counterparties. The Company uses a credit management process to assess and monitor the financial conditions of counterparties. Credit exposure is also regularly monitored by the RMC. The Company provides for losses due to market and credit risk. PNM's credit risk with its largest counterparty as of December 31, 2003 was $23.5 million.

The following table provides information related to PNM's credit exposure as of December 31, 2003. The Company does not hold any credit collateral as of December 31, 2003. The table further delineates that exposure by the credit worthiness (credit rating) of the counterparties and provides guidance as to the concentration of credit risk to individual counterparties PNM may have. Also provided is an indication of the maturity of a company's credit risk by credit ratings of the counterparties.

SCHEDULE OF WHOLESALE OPERATIONS CREDIT RISK EXPOSURE DECEMBER 31, 2003

RATING (A)	NET CREDIT RISK EXPOSURE (B)	NUMBER OF COUNTER-PARTIES >10%	NET EXPOSURE OF COUNTER-PARTIES >10%
	(Dollars in thousands)		(Dollars in thousands)
Investment grade	$ 46,799	2	$23,536
Non-investment grade	162	–	–
Split rating	43	–	–
Internal ratings			
Investment grade	71	–	–
Non-investment grade	18,678	1	7,055
TOTAL	**$ 65,753**		**$30,591**

(a) *Rating* – Included in "Investment Grade" are counterparties with a minimum S&P rating of BBB- or Moody's rating of Baa3. If the counterparty has provided a guarantee by a higher rated entity (e.g., its parent), determination is based on the rating of its guarantor. The "Internal Ratings - Investment Grade" includes those counterparties that are internally rated as investment grade in accordance with the guidelines established in the Company's credit policy.

(b) *The Net Credit Risk Exposure* is the net credit exposure to PNM from its Wholesale Operations. This includes long-term contracts, forward sales and short-term sales. The exposure captures the net amounts due to PNM from receivables/payables for realized transactions, delivered and unbilled revenues, and mark-to-market gains/losses (pursuant to contract terms). Exposures are offset according to legally binding netting arrangements and reduced by credit collateral. Credit collateral includes cash deposits, letters of credit and performance bonds received from counterparties. Amounts are presented before those reserves that are determined on a portfolio basis.

MATURITY OF CREDIT RISK EXPOSURE DECEMBER 31, 2003

RATING	LESS THAN 2 YEARS	2-5 YEARS	TOTAL NET EXPOSURE
	(In thousands)	(In thousands)	(In thousands)
Investment grade	$ 34,795	$ 12,004	$ 46,799
Non-investment grade	162	–	162
Split rating	43	–	43
Internal ratings			
Investment grade	71	–	71
Non-investment grade	18,678		18,678
TOTAL	**$ 53,749**	$ 12,004	$ 65,753

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Natural Gas Supply Contracts

PNM hedges certain portions of natural gas supply contracts in order to protect its retail customers from adverse price fluctuations in the natural gas market. The financial impact of all hedge gains and losses, including the related costs of the program, is recoverable through the purchased gas adjustment clause. As a result, earnings are not affected by gains and losses generated by these instruments.

Interest Rate Risk

As of December 31, 2003 the Company had liquidated its investment portfolio of fixed-rate government obligations and corporate securities.

PNM has long-term debt which subjects it to the risk of loss associated with movements in market interest rates. The majority of the Company's long-term debt is fixed-rate debt, and therefore, does not expose the Company's earnings to a major risk of loss due to adverse changes in market interest rates. However, the fair value of all long-term debt instruments would increase by approximately 3.25% or $33.2 million if interest rates were to decline by 50 basis points from their levels at December 31, 2003. As of December 31, 2003, the fair value of PNM's long-term debt was $1,029 million as compared to a book-value of $987 million. In general, an increase in fair value would impact earnings and cash flows if PNM were to re-acquire all or a portion of its debt instruments in the open market prior to their maturity.

During the twelve months ended December 31, 2003, PNM contributed cash of $20.0 million and approximately $28.9 million in Holding Company common shares for plan year 2002 and 2003 to the trust for the Company's pension plan. In addition, the Company contributed cash of approximately $6.2 million to other post retirement benefits for plan year 2003. The securities held by the trusts had an estimated fair value of $563.7 million as of December 31, 2003, of which approximately 29% were fixed-rate debt securities that subject the Company to risk of loss of fair value with movements in market interest rates. If rates were to increase by 50 basis points from their levels at December 31, 2003, the decrease in the fair value of the securities would be 2.8% or $4.6 million. PNM does not currently recover or return through rates any losses or gains on these securities. The Company, therefore, is at risk for shortfalls in its funding of its obligations due to investment losses. The Company does not believe that long-term market returns over the period of funding will be less than required for the Company to meet its obligations. However, this belief is based on assumptions about future returns that are inherently uncertain.

Equity Market Risk

PNM contributes to trusts established to fund its share of the decommissioning costs of PVNGS and pension and other post-retirement benefits. The trusts hold certain equity securities as of December 31, 2003. These equity securities also expose the Company to losses in fair value. Approximately 63% of the securities held by the various trusts were equity securities as of December 31, 2003. The Company is currently implementing a change in the asset allocation in the pension portfolio, which will reduce the domestic equity exposure from 55% to 47.5%. Similar to the debt securities held for funding decommissioning and certain pension and other post-retirement costs, PNM does not recover or earn a return through rates on any losses or gains on these equity securities.

In 2001, the Company implemented an enhanced cash management strategy using derivative instruments based on the S&P 100, S&P 500, and Nasdaq composite indices. The strategy is designed to capitalize on high market volatility or benefit from market direction. An investment manager is utilized to execute the program. The risk related to the program is carefully managed by the RMC and has VAR and stop-loss limits established. Trades are typically closed-out before the end of a reporting period and within the same day of execution. In January 2004, the Company terminated the use of this derivative trading strategy for the enhanced cash management program.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS AND REPORT OF INDEPENDENT ADITORS

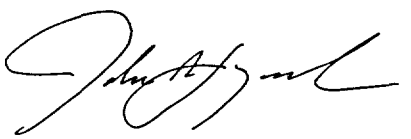
The accompanying financial statements of PNM Resources, Inc. and its subsidiaries and Public Service Company of New Mexico and its subsidiaries, a wholly owned subsidiary of PNM Resources, Inc., have been prepared in conformity with accounting principles generally accepted in the United States of America.

The integrity and objectivity of data in these financial statements and accompanying notes, including estimates and judgments related to matters not concluded by year-end, are the responsibility of management as is all other information in this Annual Report. Management devotes ongoing attention to review and appraisal of its system of internal controls. This system is designed to provide reasonable assurance, at an appropriate cost, that PNM Resources, Inc.'s and Public Service Company of New Mexico's assets are protected, that transactions and events are recorded properly and that financial reports are reliable. The system is augmented by a staff of corporate auditors; careful attention to selection and development of qualified financial personnel; and programs to further timely communication and monitoring of policies, standards and delegated authorities.

The Audit and Ethics Committee of the Board of Directors of PNM Resources, Inc., composed entirely of outside directors who meet the independence criteria established by the NYSE, meets regularly with the financial managers, the corporate auditors and the independent auditors to review the work of each. The independent auditors and corporate auditors have free access to the Committee, without management representatives present, to discuss the results of their audits and their comments on the adequacy of internal controls and the quality of financial reporting.

Jeffry E. Sterba, Chairman, President and Chief Executive Officer and John R. Loyack, Senior Vice President and Chief Financial Officer have each filed the certification required under Section 302 of the Sarbanes-Oxley Act in the 2003 Form 10-K. The certifications can be found as Exhibit 31.1 and 31.2 in the Form 10-K.

JEFFRY E. STERBA



JOHN R. LOYACK

Independent Auditors' Report

TO THE BOARD OF DIRECTORS AND STOCKHOLDERS OF PNM RESOURCES, INC.

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of PNM Resources, Inc. and subsidiaries (the "Company") as of December 31, 2003 and 2002, and the related consolidated statements of earnings, retained earnings, comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2003 and 2002, and results of their operations and their cash flows for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations, effective January 1, 2003. As discussed in Note 9 to the consolidated financial statements, during 2003, the Company changed the actuarial valuation measurement date for the pension plan and other post-retirement benefit plans from September 30 to December 31.

DELOITTE & TOUCHE LLP
Omaha, Nebraska
March 8, 2004

CONSOLIDATED STATEMENTS OF EARNINGS

Consolidated Statements of Earnings (In thousands, except per share amounts)

	YEAR ENDED DECEMBER 31,		
	2003	2002	2001
Operating Revenues: *(notes 1 and 2)*			
Electric	$ 1,097,136	$ 839,884	$ 1,881,375
Gas	358,267	277,406	371,265
Other	311	1,404	1,538
TOTAL OPERATING REVENUES	1,455,714	1,118,694	2,254,178
Operating Expenses:			
Cost of energy sold	802,731	499,751	1,438,646
Administrative and general	158,706	146,231	155,392
Energy production costs	140,584	149,528	152,455
Depreciation and amortization	115,649	102,409	96,936
Transmission and distribution costs	60,070	63,870	69,001
Taxes, other than income taxes	31,310	34,244	30,302
Income taxes (notes 1 and 8)	28,072	20,887	88,769
TOTAL OPERATING EXPENSES	1,337,122	1,016,920	2,031,501
OPERATING INCOME	118,592	101,774	222,677
Other Income and Deductions *(note 16)*:			
Other income	52,705	48,360	52,147
Other deductions	(46,153)	(12,306)	(67,257)
Income tax (expense) benefit (notes 1 and 8)	183	(12,144)	7,706
NET OTHER INCOME AND DEDUCTIONS	6,735	23,910	(7,404)
EARNINGS BEFORE INTEREST CHARGES	125,327	125,684	215,273
Interest Charges:			
Interest on long-term debt (note 4)	59,429	56,409	62,716
Other interest charges	6,760	5,003	2,124
NET INTEREST CHARGES	66,189	61,412	64,840
PREFERRED STOCK DIVIDEND REQUIREMENTS OF SUBSIDIARY	586	586	586
NET EARNINGS BEFORE CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES	58,552	63,686	149,847
CUMULATIVE EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES NET OF TAX OF $23,999 (NOTES 9, 12 AND 17)	36,621	–	–
NET EARNINGS	$ 95,173	$ 63,686	$ 149,847
Net Earnings per Common Share *(note 7)*:			
Basic	$ 2.39	$ 1.63	$ 3.83
Diluted	$ 2.37	$ 1.61	$ 3.77
DIVIDENDS PAID PER SHARE OF COMMON STOCK	$ 0.91	$ 0.86	$ 0.80

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

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS
CONSOLIDATED BALANCE SHEETS

Consolidated Statements of Retained Earnings (In thousands)

	YEAR ENDED DECEMBER 31,		
	2003	2002	2001
BALANCE AT BEGINNING OF YEAR	$ 444,651	$ 415,388	$ 296,843
Net earnings	95,173	63,686	149,847
Dividends (note 4):			
Common stock	(36,755)	(34,423)	(31,302)
BALANCE AT END OF YEAR	$ 503,069	$ 444,651	$ 415,388

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

Consolidated Balance Sheets (In thousands)

ASSETS

	YEAR ENDED DECEMBER 31,	
	2003	2002
Utility Plant: (notes 1, 11 and 13)		
Electric plant in service	$ 2,419,162	$ 2,301,673
Gas plant in service	630,949	615,907
Common plant in service and plant held for future use	48,735	79,987
	3,098,846	2,997,567
Less accumulated depreciation and amortization	1,063,645	1,102,443
	2,035,201	1,895,124
Construction work in progress	133,317	173,248
Nuclear fuel, net of accumulated amortization of $15,995 and $16,568	25,917	26,832
Net utility plant	2,194,435	2,095,204
Other Property and Investments:		
Investment in lessor notes (notes 5 and 6)	330,339	350,479
Other investments (notes 1 and 6)	114,273	92,225
Non-utility property, net of accumulated depreciation of $1,755 and $1,750	1,455	1,528
TOTAL OTHER PROPERTY AND INVESTMENTS	446,067	444,232
Current Assets:		
Cash and cash equivalents	12,694	3,702
Accounts receivables, net of allowance for uncollectible accounts of $9,284 and $15,575	68,258	46,914
Unbilled revenues (note 1)	82,899	68,438
Other receivables	47,042	53,052
Inventories (note 1)	40,799	37,230
Regulatory assets (note 3)	15,436	1,061
Short-term investments (notes 1 and 6)	–	79,630
Other current assets	38,835	32,753
TOTAL CURRENT ASSETS	305,963	342,780
Deferred charges:		
Regulatory assets (note 3)	215,416	196,283
Prepaid retirement cost (note 9)	85,782	39,665
Other deferred charges	130,966	129,063
TOTAL DEFERRED CHARGES	432,164	365,011
	$ 3,378,629	$ 3,247,227

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

CONSOLIDATED BALANCE SHEETS

CAPITALIZATION AND LIABILITIES

	AS OF DECEMBER 31, 2003	2002
Capitalization:		
Common stockholders' equity:		
Common stock outstanding 40,259 and 39,118 shares, no par value (note 4)	$ 647,722	$ 624,119
Accumulated other comprehensive loss, net of tax (note 1)	(73,487)	(94,721)
Retained earnings	503,069	444,651
TOTAL COMMON STOCKHOLDERS' EQUITY	1,077,304	974,049
Minority interest (notes 1 and 5)	–	11,760
Cumulative preferred stock without mandatory redemption requirements (note 4)	12,800	12,800
Long-term debt (note 4)	987,210	980,092
TOTAL CAPITALIZATION	2,077,314	1,978,701
Current Liabilities:		
Short-term debt	125,918	150,000
Accounts payable	86,155	90,355
Accrued interest and taxes (notes 1 and 8)	23,477	46,189
Other current liabilities	110,031	99,019
TOTAL CURRENT LIABILITIES	345,581	385,563
Deferred Credits:		
Accumulated deferred income taxes (notes 1 and 8)	250,098	139,732
Accumulated deferred investment tax credits (notes 1 and 8)	38,462	41,583
Regulatory liabilities (note 3)	316,384	279,952
Asset retirement obligations (note 12)	46,416	–
Minimum pension liability	128,825	141,175
Accrued post-retirement benefit cost (note 9)	20,638	17,335
Other deferred credits (note 14)	154,911	263,186
TOTAL DEFERRED CREDITS	955,734	882,963
Commitments and Contingencies (note 13)	–	–
	$ 3,378,629	$ 3,247,227

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

Consolidated Statements of Cash Flows (In thousands)

	AS OF DECEMBER 31,		
	2003	2002	2001
Cash Flows From Operating Activities:			
Net earnings	$ 95,173	$ 63,686	$ 149,847
Adjustments to reconcile net earnings to net cash flows from operating activities:			
Depreciation and amortization	144,854	115,415	106,768
Allowance for equity funds used during construction	(2,589)	–	–
Accumulated deferred income tax	90,175	44,138	(36,066)
Transition costs write-off	16,720	–	–
Loss on reacquired debt	18,575	–	–
Cumulative effect of a change in accounting principle	(60,620)	–	–
Asset write-offs	–	4,817	36,496
Merger costs	–	(2,436)	17,975
Net unrealized losses on trading and investment contracts	(1,360)	(29,513)	26,172
Wholesale credit reserve	(2,433)	–	(5,406)
Other, net	–	2,083	(4,297)
Changes in certain assets and liabilities:			
Accounts receivables	(21,344)	2,830	36,297
Unbilled revenues	5,539	3,936	22,765
Accrued post-retirement benefit costs	(14,962)	(18,986)	2,873
Other assets	(5,972)	(41,152)	17,841
Accounts payable	(7,317)	34,597	(91,378)
Accrued interest and taxes	(22,712)	(25,833)	35,133
Other liabilities	(1,036)	(56,223)	12,326
NET CASH FLOWS FROM OPERATING ACTIVITIES	228,692	97,359	327,346
Cash Flows From Investing Activities:			
Utility plant additions	(167,701)	(229,629)	(253,899)
Nuclear fuel additions	(9,503)	(10,596)	(10,945)
Redemption of available-for-sale investments	80,291	76,633	(150,000)
Combustion turbine payments	(11,136)	(29,975)	–
Bond purchase	(8,675)	(5,572)	–
Return of principal PVNGS lessor notes	18,360	17,531	16,674
Merger acquisition costs	–	–	(11,567)
Other	(5,203)	(18,819)	2,723
NET CASH FLOWS FROM INVESTING ACTIVITIES	(101,567)	(200,427)	(407,014)
Cash Flows From Financing Activities:			
Short-term borrowings (repayments), net (note 4)	(24,082)	115,000	35,000
Long-term debt borrowings	483,882	–	–
Long-term debt repayments	(476,572)	–	–
Premium on long-term debt refinancing	(23,905)	–	–
Refund costs of pollution control bonds	(31,427)	–	–
Exercise of employee stock options (note 10)	(9,639)	(2,412)	(2,179)
Dividends paid	(36,702)	(34,226)	(31,876)
Other	312	–	(560)
NET CASH FLOWS FROM FINANCING ACTIVITIES	(118,133)	78,362	385
Increase (Decrease) in Cash and Cash Equivalents	8,992	(24,706)	(79,283)
Beginning of Year	3,702	28,408	107,691
End of Year	$ 12,694	$ 3,702	$ 28,408
Supplemental Cash Flow Disclosures:			
Interest paid, net of capitalized interest	$ 69,046	$ 53,041	$ 62,216
Income taxes paid (refunded), net	$ (23,154)	$ 13,541	$ 72,146
Non Cash Transactions:			
Long-term debt assumed for transmission line	$ –	$ 26,152	$ –
Pension contribution of PNM Resources, Inc. common shares	$ 28,950	$ –	$ –

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

CONSOLIDATED STATEMENTS OF CAPITALIZATION

Consolidated Statements of Capitalization (In thousands)

	AS OF DECEMBER 31, 2003	2002
Common Stock Equity:		
Common Stock, no par value (note 4)	$ 647,722	$ 624,119
Accumulated other comprehensive income, net of tax (note 1)	(73,487)	(94,721)
Retained earnings	503,069	444,651
TOTAL COMMON STOCK EQUITY	1,077,304	974,049
Minority Interest (notes 1 and 5)	–	11,760
Cumulative Preferred Stock: (note 4)		
Without mandatory redemption requirements:		
1965 Series, 4.58% with a stated value of $100.00 and a current redemption price of $102.00. Outstanding shares at December 31, 2003 and 2002 were 128,000	12,800	12,800
Long-Term Debt: (note 4)		
Issue and Final Maturity		
First Mortgage Bonds, Pollution Control Revenue Bonds:		
5.7% due 2016	65,000	65,000
6.375% due 2022	–	46,000
TOTAL FIRST MORTGAGE BONDS	65,000	111,000
Senior Unsecured Notes, Pollution Control Revenue Bonds:		
6.30% due 2016	77,045	77,045
5.75% due 2022	37,300	37,300
5.80% due 2022	100,000	100,000
6.375% due 2022	90,000	90,000
6.375% due 2023	–	36,000
6.40% due 2023	–	100,000
6.30% due 2026	23,000	23,000
6.60% due 2029	11,500	11,500
2.75% due 2033	46,000	–
2.75% due 2033	100,000	–
2.75% due 2038	36,000	–
TOTAL SENIOR UNSECURED NOTES, POLLUTION CONTROL REVENUE BONDS	520,845	474,845
Senior Unsecured Notes:		
7.10% due 2005	–	268,420
4.40% due 2008	300,000	–
7.50% due 2018	100,025	100,025
EIP debt	–	26,152
Other, including unamortized discounts	1,340	(350)
Total long-term debt	987,210	980,092
TOTAL CAPITALIZATION	$ 2,077,314	$ 1,978,701

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

Consolidated Statements of Comprehensive Income (Loss) (In thousands)

	AS OF DECEMBER 31,		
	2003	2002	2001
NET EARNINGS	$ 95,173	$ 63,686	$ 149,847
Other Comprehensive Income (Loss):			
UNREALIZED GAIN (LOSS) ON SECURITIES:			
Unrealized holding gains arising during the period, net of tax expense of $1,256, $853 and $46	1,916	1,303	70
Reclassification adjustment for losses included in net income, net of tax benefit of $440, $602 and $345	(672)	(919)	(526)
MINIMUM PENSION LIABILITY ADJUSTMENT			
Net of tax expense (benefit) of $6,284, $(36,085) and $(18,912)	9,589	(55,061)	(28,858)
MARK-TO-MARKET ADJUSTMENT FOR CERTAIN DERIVATIVE TRANSACTIONS:			
Initial implementation of SFAS 133 designated cash flow hedges, net of tax expense of $4,029	–	–	6,148
Change in fair market value of designated cash flow hedges, net of tax expense (benefit) of $6,816, $(6,790) and $226	10,401	(10,361)	345
Reclassification adjustment for losses included in net income, net of tax benefit of $450 and $4,029	–	(687)	(6,148)
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	21,234	(65,725)	(28,969)
TOTAL COMPREHENSIVE INCOME (LOSS)	$ 116,407	$ (2,039)	$ 120,878

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2003, 2002, 2001

(1) SUMMARY OF THE BUSINESS AND SIGNIFICANT ACCOUNTING POLICIES

Nature of Business

PNM Resources, Inc. (the "Holding Company") is an investor-owned holding company of energy and energy related businesses. Its principal subsidiary, Public Service Company of New Mexico ("PNM"), is an integrated public utility primarily engaged in the generation, transmission, distribution and sale and marketing of electricity; transmission, distribution and sale of natural gas within the State of New Mexico and the sale and marketing of electricity in the Western United States. The business of PNM constitutes substantially all of the business of Holding Company and its subsidiaries. Therefore, the financial results and results of operations of PNM are virtually identical to the consolidated results of the Holding Company and its subsidiaries. For ease of discussion, these notes may use the term "Company" when referring to PNM or when discussing matters of common applicability to the Holding Company and PNM. In addition, the Holding Company provides energy and utility related services under its wholly-owned subsidiary, Avistar, Inc. ("Avistar").

Upon the completion on December 31, 2001, of a one-for-one share exchange between PNM and the Holding Company, the Holding Company became the parent company of PNM. Prior to the share exchange, the Holding Company had existed as a subsidiary of PNM. The new parent company began trading on the New York Stock Exchange under the same PNM symbol beginning on December 31, 2001.

Presentation

The Notes to Consolidated Financial Statements of the Company are presented on a combined basis. The Holding Company assumed substantially all of the corporate activities of PNM on December 31, 2001. These activities are billed to PNM on a cost basis to the extent they are for the corporate management of PNM and are allocated to the operating segments. In January 2002, Avistar and certain inactive subsidiaries of PNM were transferred by way of a dividend to the Holding Company pursuant to an order from the New Mexico Public Regulation Commission ("PRC"). Readers of the Notes to Consolidated Financial Statements should assume that the information presented applies to the consolidated results of operations and financial position of both the Holding Company and its subsidiaries and PNM, except where the context or references clearly indicate otherwise. Discussions regarding specific contractual obligations generally reference the company that is legally obligated. In the case of contractual obligations of PNM, these obligations are consolidated with the Holding Company and its subsidiaries under generally accepted accounting principles ("GAAP"). Broader operational discussions refer to the Company.

Accounting Principles

The Company maintains its accounting records in accordance with the uniform system of accounts prescribed by the Federal Energy Regulatory Commission ("FERC") and the National Association of Regulatory Utility Commissioners, and adopted by the New Mexico Public Regulation Commission ("PRC").

The Company's accounting policies conform to the provisions of Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation" ("SFAS 71"). SFAS 71 requires a rate-regulated entity to reflect the effects of certain regulatory decisions in its financial statements. In accordance with SFAS 71, the Company has deferred certain costs and recorded certain liabilities pursuant to the rate actions of the FERC, and the PRC and its predecessor. These "regulatory assets" and "regulatory liabilities" are enumerated and discussed in Note 3.

The Company discontinued the application of SFAS 71 as of December 31, 1999, for the generation portion of its business effective with the passage of the Electric Utility Industry Restructuring Act of 1999 ("Restructuring Act") in accordance with Statement of Financial Accounting Standards No. 101, "Accounting for the Discontinuation of Application of FASB Statement No. 71" ("SFAS 101"). In October 2002, the Company and several other parties signed the Global Electric Agreement that provided for a five-year rate path for the Company's New Mexico jurisdictional customers beginning in September of 2003 (see Note 13 for further discussion). In response to the Global Electric Agreement, the New Mexico Legislature repealed the Restructuring Act. As a result, the Company re-applied SFAS 71 to its generation portion of its business during the first quarter of 2003 as a result of the PRC approving the Global Electric Agreement in January 2003.

Principles of Consolidation

The consolidated financial statements include the accounts of the Company and subsidiaries in which it owns a majority voting interest. Corporate administrative and general expenses, which represent costs that are driven primarily by corporate level activities, are allocated to the business segments. There were no other significant intercompany transactions between the Holding Company and PNM in 2003 and 2002, except for the common dividend, consolidation of PVNGS capital trust and minority interest described in Note 5. All significant intercompany transactions and balances have been eliminated.

The Company adopted Statement of Financial Accounting Standards No. 150 "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity" ("SFAS 150"). SFAS 150 established standards for classifying and measuring certain financial instruments with characteristics of both liabilities and equity. Under SFAS 150, issuers are required to classify as liabilities a financial instrument that is within its scope as a liability because that financial instrument embodies an obligation of the issuer. SFAS 150 is effective for financial instruments entered into or modified after May 31, 2003. The FASB has indefinitely deferred the classification and measurement provisions and adoption of SFAS 150 in relation to limited life entities. Upon adoption, the Company reclassified approximately $10 million from minority interest to other deferred credits on its consolidated balance sheets at December 31, 2003.

Financial Statement Preparation

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual recorded amounts could differ from those estimated.

Cash and Cash Equivalents

All liquid investments with maturities of three months or less at the date of purchase are considered cash equivalents.

Utility Plant

Utility plant is stated at cost, which includes capitalized payroll-related costs such as taxes, pension and other fringe benefits, administrative costs, an allowance for funds used during construction and any carrying value adjustment as deemed appropriate.

It is Company policy to charge repairs and minor replacements of property to maintenance expense and to charge major replacements to utility plant. Gains or losses resulting from retirements or other dispositions of regulated property in the normal course of business are credited or charged to the accumulated provision for depreciation.

Allowance For Funds Used During Construction ("AFUDC")

As provided by the uniform systems of accounts, AFUDC is charged to utility plant. AFUDC represents the cost of borrowed funds (allowance for borrowed funds used during construction) and a return on other funds (allowance for equity funds used during construction).

The calculation of AFUDC should be performed if its subsequent inclusion in allowable costs for rate-making purposes is probable. In 2003, PNM recorded $3.9 million of AFUDC on certain construction projects. PNM did not record AFUDC on construction projects in 2002 and 2001.

Capitalized Interest

SFAS 34, "Capitalization of Interest Costs," requires that interest cost be capitalized as part of the historical cost of acquiring certain assets and is calculated using only the cost of borrowing. Under GAAP, interest can only be capitalized on non-SFAS 71 assets. PNM capitalizes interest on its generation projects not included in rate base that are under construction and software costs. The interest cost to be capitalized is theoretically that portion of interest expense that could have been avoided if construction expenditures were not made. The rate used for capitalization is the rate for borrowings specific to the project. If there are no specific borrowings, the weighted average borrowing rate for the Company is used. PNM has not borrowed any funds specifically for any projects; therefore interest was being capitalized at the overall weighted average borrowing rate of 6.4%. PNM's capitalized interest was $1.2 million and $6.4 million in 2003 and 2002, respectively. No interest was capitalized in 2001.

Inventories

Inventory consists principally of materials and supplies, natural gas held in storage for eventual resale, and coal held for use in electric generation.

Generally, materials and supplies include the costs of transmission, distribution and generating plant materials. Materials and supplies are charged to inventory when purchased and are expensed or capitalized as appropriate when issued. Materials and supplies are valued using an average costing method. Obsolete materials and supplies are immediately expensed when identified.

Gas in underground storage is valued using a weighted average inventory method. Withdrawals are charged to sales service customers through the Purchased Gas Adjustment Clause ("PGAC"). Adjustments to gas in underground storage due to migration are charged to the PGAC and are based on a PRC pre-approved percentage of injections.

Coal is valued using a rolling weighted average costing method that is updated based on the current period cost per tons. Periodic aerial surveys are performed and any material adjustments are recorded as identified.

Inventories consisted of the following at December 31, (in thousands).

	2003	2002
Coal	**$ 11,282**	$ 12,678
Gas in underground storage	**4,295**	2,001
Materials and supplies	**25,222**	22,551
	$ 40,799	$ 37,230

Investments

The Company's investments are comprised of U.S., state, and municipal government obligations and corporate securities. Investments with maturities of less than one year are considered short-term and are carried at fair value. All investments are held in the Company's name and are in the custody of major financial institutions. The specific identification method is used to determine the cost of securities disposed of, with realized

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2003, 2002, 2001

gains and losses reflected in other income and expense. At December 31, 2003 and 2002, all of the Company's investments were classified as available for sale. Unrealized gains and losses on these investments are included in other comprehensive income, net of any related tax effect.

Revenue Recognition

The Company's Utility Operations record electric and gas operating revenues in the period of delivery, which includes estimated amounts for service rendered but unbilled at the end of each accounting period.

The determination of the energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. Unbilled electric revenue is estimated based on the daily generation volumes, estimated customer usage by class, weather factors, line losses and applicable customer rates based on regression analyses reflecting historical trends and experience.

The Company purchases gas on behalf of sales-service customers while other marketers or producers purchase gas on behalf of transportation-service customers. The Company collects a cost of service revenue for the transportation, delivery, and customer service provided to these customers. Sales-service tariffs are subject to the terms of the PGAC while transportation service customers are metered and billed on the last day of the month. Therefore, the Company estimates unbilled decatherms and records cost of service and PGAC revenues for sales-service customers only.

The Company's Wholesale Operations revenues are recognized in the month the energy is delivered to the customer and are based on the actual amounts supplied to the customer. However, in accordance with the Western Systems Power Pool contract, these revenues are billed in the month subsequent to their delivery. Consequently, wholesale revenues for the last month in any reporting period are unbilled when reported.

These electricity sales are recorded as operating revenues while the electricity purchases are recorded as costs of energy sold. These amounts were recorded on a gross basis, because the Company does not act as an agent or broker for these merchant energy contracts but takes title and has the risks and rewards of ownership. Effective October 1, 2003, non-normal derivative contracts that are net settled or "booked-out" are recorded net in operating revenues. A book-out is the unplanned netting of off-setting purchase and sale transactions. A book-out is a transmission mechanism to reduce congestion on the transmission system or administrative burden (see further discussion in Financial Instruments in this same footnote). Specifically, adopting EITF Issue 03-11 "Reporting 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" ("EITF 03-11") affected the comparability of 2003 Consolidated Financial Statements to those of prior years. The Consolidated Statements of Income for 2002 and 2001 were not reclassified.

The Company enters into merchant energy contracts to take advantage of market opportunities associated with the purchase and sale of electricity. Unrealized gains and losses resulting from the impact of price movements on the Company's derivative energy contracts that are not designated normal purchases and sales or hedges are recognized as adjustments to Wholesale Operations operating revenues. The market prices used to value these transactions reflect management's best estimate considering various factors including closing exchange and over-the-counter quotations, time value and volatility factors underlying the commitments.

Depreciation and Amortization

Provision for depreciation and amortization of utility plant is made based upon rates approved by the PRC. The average rates used are as follows:

	2003	2002	2001
Electric plant	3.33%	3.42%	3.39%
Gas plant	2.96%	3.02%	3.21%
Common plant	6.38%	7.34%	6.92%

The provision for depreciation of certain equipment is charged to depreciation expense and allocated to construction projects based on the use of the equipment. Depreciation of non-utility property is computed based on the straight-line method. Amortization of nuclear fuel is computed based on the units of production method.

Decommissioning Costs

Accounting for decommissioning costs for nuclear and fossil-fuel generation involves significant estimates related to costs to be incurred many years in the future after plant closure. Changes in these estimates could significantly impact the Company's financial position, results of operation and cash flows. The Company owns and leases nuclear and fossil-fuel facilities that are within and outside of its retail service areas. The Company adopted the accounting requirements of Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" ("SFAS 143") on January 1, 2003 (see Note 12). Under SFAS 143, the Company is only required to recognize and measure decommissioning liabilities for tangible long-lived assets for which a legal obligation exists. Adoption of the statement changed the Company's method of accounting for both nuclear generation decommissioning and fossil-fuel generation decommissioning. Nuclear decommissioning costs are based on site-specific estimates of the costs for removing all radioactive and other structures at the site. PVNGS Unit 3 is currently excluded from the Company's

retail rates base while Units 1 and 2 are included in the Company's retail rates. The Company collects a provision for ultimate decommissioning of Units 1 and 2 in its rates and recognizes a corresponding expense and liability for these amounts. Fossil-fuel decommissioning costs are also approved by the PRC as a component of the Company's depreciation rates. The Company believes that it will continue to be able to collect for its legal asset retirement obligations for nuclear and fossil-fuel generation activities included in the ratemaking process.

In addition, the Company has a contractual obligation with the PVNGS participants to fund separately the nuclear decommissioning at a level in excess of what the Company has identified as its legal asset retirement obligation under SFAS 143. The contractual funding obligation is based on a site-specific estimate prepared by a third party. The Company's most recent site-specific estimates for nuclear decommissioning costs were developed in 2001, using 2001 cost factors, and are based on prompt dismantlement decommissioning, reflecting the costs of removal discussed above, with such removal occurring shortly after operating license expiration. The Company's share of the contractual funding obligation through the end of the licensing terms is approximately $201 million (measured in 2001 dollars). The estimates are subject to change based on a variety of factors, including cost escalation, changes in technology applicable to nuclear decommissioning and changes in federal, state or local regulations. The operating licenses for PVNGS Units 1, 2 and 3 will expire in 2025, 2026, and 2027, respectively. The Company does not have a similar contractual funding obligation related to its fossil-fuel plants.

Amortization of Debt Acquisition Costs

Discount, premium and expense related to the issuance of long-term debt are amortized over the lives of the respective issues. In connection with the early retirement of long-term debt, such amounts associated with resources subject to PRC regulation are amortized over the lives of the respective issues. Amounts associated with the Company's firm-requirements wholesale customers and its resources excluded from PRC retail rates are recognized immediately as expense or income as they are incurred.

Financial Instruments

Effective January 1, 1999, the Company adopted EITF Issue No. 98-10 which requires that energy trading contracts be marked-to-market (measured at fair value determined as of the balance sheet date with the gains and losses included in earnings).

The Company implemented SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," ("SFAS 133"), as amended, on January 1, 2001. SFAS 133, as amended, establishes accounting and reporting standards requiring derivative instruments to be recorded in the balance sheet as either an asset or liability measured at their fair value. SFAS 133, as amended, also requires that changes in the derivatives' fair value be recognized currently in earnings unless specific hedge accounting or normal purchase and sale criteria are met. Special accounting for qualifying hedges allows derivative gains and losses to offset related results on the hedged item in the income statement, and requires that a company must formally document, designate, and assess the effectiveness of transactions that receive hedge accounting. SFAS 133, as amended, provides that the effective portion of the gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument be reported as a component of other comprehensive income and be reclassified into earnings in the same period or periods during which the hedged forecasted transaction affects earnings. The results of hedge ineffectiveness and the change in fair value of a derivative that an entity has chosen to exclude from hedge effectiveness are required to be presented in current earnings. All energy contracts marked-to-market under EITF 98-10 were subject to mark-to-market accounting upon adoption of SFAS 133.

On October 25, 2002, the EITF reached a final consensus on EITF 02-3 "Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities", EITF 98-10 "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" and Statement of Financial Accounting Standards No. 133 "Accounting for Derivative Instruments and Hedging Activities" ("SFAS 133") that rescinded EITF 98-10 and required that all energy contracts held for trading purposes be presented on a net margin basis in the statement of earnings. The rescission of EITF 98-10 requires that energy contracts which do not meet the definition of a derivative under SFAS 133 no longer be marked to market and recognized in current earnings. As a result, all contracts which were marked to market under EITF 98-10 and must now be accounted for under the accrual method and written back to cost with any difference included as a cumulative effect of a change in accounting principle in the period of adoption. This transition provision was effective January 1, 2003. The rescission of EITF 98-10 did not have a material impact on the Company's financial condition or results of operations as all contracts previously marked to market under the definition provided in EITF 98-10 also met the definition of a derivative under SFAS 133 and are properly recorded at fair value with gains and losses recorded in earnings. The Company reviewed its energy contract portfolio to determine whether its contracts meet the definition of trading activities under EITF 02-3. As a result, the Company has reclassified those contracts previously accounted for under EITF 98-10 to a net margin basis for the fiscal years ended December 31, 2002 and 2001. The Company will not report revenues and cost of energy sold on a net margin basis on a prospective basis as a result of the application of EITF 02-3 as none of the Company's marketing activities meet the definitions of trading activities as prescribed by EITF 02-3. For the years ended December 31, 2002 and 2001, wholesale purchases of $74.0 million and $89.4 million were netted with electric revenues in the consolidated statement of earnings (see Note 2).

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Statement of Financial Accounting Standards No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" ("SFAS 149") was effective for all electricity contracts entered into by the Company or modified after June 30, 2003. Under SFAS 149, the Company treats all forward electric purchases and sales contracts subject to unplanned netting or book-out by the transmission provider as derivative instruments subject to mark-to-market accounting, unless the contract qualifies for the normal exception by meeting SFAS 149's definition of a capacity contract. Under this definition, the contract cannot permit net settlement, the seller must have the resources to serve the contract and the buyer must be a load serving entity. Upon adoption, SFAS 149 did not have a material impact on the Company's financial condition or results of operation.

EITF 03-11 was effective for the Company on October 1, 2003. EITF 03-11 gives guidance on whether realized gains and losses on derivative contracts not held for trading purposes should be reported on a net or gross basis and concludes such classification is a matter of judgment that depends on the relevant facts and circumstances. The Company nets all realized gains and losses on non-normal derivative transactions that do not physically deliver and that are offset by similar transactions during settlement. For the year ended December 31, 2003, wholesale purchases of $15.0 million were netted with electric revenues in the consolidated statement of earnings (see Note 2).

Stock Based Compensation

The Company accounts for stock-based compensation using the intrinsic value method prescribed in Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees." Compensation cost for stock options, if any, is measured as the excess of the quoted market price of the Company's stock at the date of grant over the exercise price of the granted stock option. Restricted stock is recorded as compensation cost over the requisite vesting periods based on the market value on the date of grant.

At December 31, 2003, the Company had three stock-based employee compensation plans of which stock options continue to be granted under only two of the plans. These plans are described more fully in Note 10. Had compensation expense for the Company's stock options been recognized based on the fair value on the grant date under the methodology prescribed by SFAS No. 123, "Accounting for Stock-Based Compensation" ("SFAS 123"), the effect on the Company's pro form a net earnings and pro form a earnings per share would be as follows (in thousands, except per share data):

	YEAR ENDED DECEMBER 31,		
	2003	2002	2001
NET EARNINGS:	$ 95,173	$ 63,686	$ 149,847
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(2,200)	(4,402)	(3,351)
PRO FORM A NET EARNINGS	$ 92,973	$ 59,284	$ 146,496
Earnings per share:			
Basic – as reported	$ 2.39	$ 1.63	$ 3.83
Basic – pro form a	$ 2.34	$ 1.52	$ 3.74
Diluted – as reported	$ 2.37	$ 1.61	$ 3.77
Diluted – pro form a	$ 2.32	$ 1.50	$ 3.69

Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) reports a measure for accumulated changes in equity of the Company that results from transactions and other economic events other than transactions with shareholders. The following table sets forth the changes in each component of accumulated other comprehensive income (loss) (In thousands):

	UNREALIZED GAIN (LOSS) ON SECURITIES	MINIMUM PENSION LIABILITY	MARK-TO-MARKET FOR CERTAIN DERIVATIVE TRANSACTIONS	ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)
BALANCE AT DECEMBER 31, 2000	$ (1,518)	$ 1,545	$ –	$ 27
Period change in:				
Minimum pension liability adjustment	–	28,858	–	28,858
Unrealized holding gains arising from the period	(70)	–	–	(70)
Reclassification adjustment for losses included in net income	526	–	–	526
Initial implementation of SFAS 133 designated cash flow hedges	–	–	6,148	6,148
Change in fair market value of designated cash flow hedges	–	–	(345)	(345)
Reclassification adjustment for losses included in net income	–	–	(6,148)	(6,148)
BALANCE AT DECEMBER 31, 2001	(1,062)	30,403	(345)	28,996
Period change in:				
Minimum pension liability adjustment	–	55,061	–	55,061
Unrealized holding gains arising from the period	(1,303)	–	–	(1,303)
Reclassification adjustment for losses included in net income	919	–	–	919
Change in fair market value of designated cash flow hedges	–	–	10,361	10,361
Reclassification adjustment for losses included in net income	–	–	687	687
BALANCE AT DECEMBER 31, 2002	(1,446)	85,464	10,703	94,721
Period change in:				
Minimum pension liability adjustment	–	(9,589)	–	(9,589)
Unrealized holding gains arising from the period	(1,916)	–	–	(1,916)
Reclassification adjustment for losses included in net income	672	–	–	672
Change in fair market value of designated cash flow hedges	–	–	(10,401)	(10,401)
BALANCE AT DECEMBER 31, 2003	$ (2,690)	$ 75,875	$ 302	$ 73,487

Income Taxes

The Company accounts for income taxes in accordance with the provisions of SFAS No. 109, "Accounting for Income Taxes" ("SFAS No. 109"), which uses the asset and liability method for accounting for income taxes. Under SFAS 109, deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying value of existing assets and liabilities and their respective tax basis. Current PRC approved rates include the tax effects of the majority of these differences. SFAS No. 109 requires that rate-regulated enterprises record deferred income taxes for temporary differences accorded flow-through treatment at the direction of a regulatory commission. The resulting deferred tax assets and liabilities are recorded at the expected cash flow to be reflected in future rates. Because the PRC has consistently permitted the recovery of previously flowed-through tax effects, the Company has established regulatory liabilities and assets offsetting such deferred tax assets and liabilities. Items accorded flow-through treatment under PRC orders, deferred income taxes and the future ratemaking effects of such taxes, as well as corresponding regulatory assets and liabilities, are recorded in the financial statements.

Asset Impairment

The Company evaluates its tangible long-lived assets in relation to their future undiscounted cash flows to assess recoverability in accordance with SFAS 144. Impairment testing of power generation assets is performed periodically in response to changes in market conditions. The Company considers its power generation assets used to supply jurisdictional and wholesale markets as a combined group due to its joint dispatch of these assets. Generation assets used primarily for reliability purposes are evaluated separately as a group. The Company did not recognize any impairment on its long-lived assets for the years 2001 through 2003.

Change in Presentation

Certain prior year amounts have been reclassified to conform to the 2003 financial statement presentation.

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(2) SEGMENT INFORMATION

The Holding Company is an investor-owned holding company of energy and energy related businesses. Its principal subsidiary, PNM, is an integrated public utility primarily engaged in the generation, transmission and distribution of electricity; transmission, distribution and sale of natural gas within the State of New Mexico; and the sale and marketing of electricity in the Western United States. In addition, the Holding Company provides energy and technology related services through its wholly owned subsidiary, Avistar.

As it currently operates, the Company's principal business segments, whose operating results are regularly reviewed by the Company's management, are Utility Operations and Wholesale Operations ("Wholesale"). Utility Operations include Electric Services ("Electric"), Gas Services ("Gas") and Transmission Services ("Transmission"). In 2003, the Company began allocating its business and results between the Electric and Wholesale segments for financial reporting purposes based on the assets allocations as mandated in the Global Electric Agreement (see Note 13 – Commitments and Contingencies – Global Electric Agreement). Certain prior period amounts have been reclassified to conform to the current year presentation. In addition, Transmission was reclassified from Electric and disclosed as its own business segment during the second quarter of 2003.

The following segment presentation is based on the methodology that the Company's management uses for making operating decisions and assessing performance of its various business activities. As such, the following presentation reports operating results without regard to the effect of accounting or regulatory changes and similar one-time items not related to normal operations. Reconciliation to the consolidated financial statements is provided.

In addition, adjustments related to EITF Issue 02-03 "Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities" and 03-11 "Reporting Realized Gains and Losses on Derivative Instruments that are subject to FASB statement No. 133 and Not Held for Trading Purposes" are excluded. These accounting pronouncements require a net presentation of trading gains and losses and realized gains and loss for certain non-trading derivatives. Management evaluates wholesale operations on a gross presentation basis due to its net asset-backed marketing strategy and the importance it places on the Company's ability to repurchase and remarket previously sold capacity. The Company has publicly referred to this as "velocity".

Utility Operations

ELECTRIC

Electric consists of the distribution and generation of electricity for retail electric customers in New Mexico. The Company provides retail electric service to a large area of north central New Mexico, including the cities of Albuquerque and Santa Fe, and certain other areas of New Mexico. Customer rates for retail electric service are set by the PRC based on the provisions of the Global Electric Agreement.

GAS

Gas distributes natural gas to most of the major communities in New Mexico, including two of New Mexico's three largest metropolitan areas, Albuquerque and Santa Fe. The Company's customer base includes both sales-service customers and transportation-service customers. PNM purchases natural gas in the open market and resells it at cost to its distribution customers. As a result, increases or decreases in gas revenues resulting from wholesale gas price fluctuations do not impact the Company's consolidated gross margin or earnings.

TRANSMISSION

The Company owns or leases transmission lines, interconnected with other utilities in New Mexico and south and east into Texas, west into Arizona, and north into Colorado and Utah. Transmission revenues consist of sales to third parties as well as to Electric and Wholesale.

Wholesale Operations

Wholesale consists of the generation and sale of electricity into the wholesale market based on three product lines that include long-term contracts, forward sales and short-term sales. The source of these sales is supply created by selling the unused capacity of jurisdictional assets as well as the capacity of the Company's wholesale, plants excluded from retail rates. Both regulated and unregulated generation is jointly dispatched in order to improve reliability, provide the most economic power to retail customers and maximize profits on any wholesale transactions.

Long-term contracts include sales to firm-requirements and other wholesale customers with multi-year arrangements. These contracts range from 2 to 17 years with an average of 7.5 years. Forward sales include third party purchases in the forward market that range from 1 month to 3 years. These transactions do not qualify as normal sales and purchases as defined in SFAS 133, and thus are generally marked to market. Short-term sales generally include spot market, hour ahead, day ahead and week ahead contracts with terms of 30 days or less. Also included in short-term sales are sales of any excess generation not required to fulfill PNM's retail load and contractual commitments. Short-term sales also cover the revenue credit to retail customers as specified in the Global Electric Agreement.

Corporate and Other

The Holding Company performs substantially all of the corporate activities of PNM. These activities are billed to PNM on a cost basis to the extent they are for the corporate management of PNM and are allocated to the operating segments. The Holding Company's wholly-owned subsidiary, Avistar, was formed in August 1999 as a New Mexico corporation and is currently engaged in certain unregulated and non-utility businesses. In January 2002, Avistar was dividended by PNM to the Holding Company pursuant to an order from the PRC.

Summarized financial information by business segment for the year ended December 31, 2003 is as follows (In thousands):

	UTILITY				
	ELECTRIC	GAS	TRANSMISSION	ELIMINATIONS	TOTAL
2003:					
Operating revenues:					
External customers	$ 543,850	$ 358,267	$ 19,453	$ –	$ 921,570
Intersegment revenues	–	–	32,499	(32,499)	–
Depreciation and amortization	63,428	22,186	10,104	–	95,718
Interest income	28,703	2,437	(34)	–	31,106
Interest charges	24,737	13,406	6,566	–	44,709
Total income tax expense (benefit)	34,649	(84)	3,233	–	37,798
Operating income	56,587	11,451	11,417	–	79,455
Segment net income (loss)	51,435	(128)	4,933	–	56,240
TOTAL ASSETS	1,429,291	509,111	275,301	–	2,213,703
GROSS PROPERTY ADDITIONS	74,922	45,616	33,901	–	154,439

	WHOLESALE	CORPORATE AND OTHER	CONSOLIDATED
2003:			
Operating revenues:			
External customers	$ 548,847	$ (14,703)(a)	$ 1,455,714
Intersegment revenues	1,535	(1,535)	–
Depreciation and amortization	14,230	5,701	115,649
Interest income	5,493	3,922	40,521
Interest charges	15,562	5,918	66,189
Total income tax expense (benefit)	12,725	(22,634)(b)	27,889
Operating income	30,997	8,140	118,592
Segment net income (loss)	19,416	(17,104)(b)	58,552
TOTAL ASSETS	425,372	739,554	3,378,629
GROSS PROPERTY ADDITIONS	14,620	8,145	177,204

(a) Reflects EITF 03-11 impact, under which wholesale revenues and the associated cost of energy of $15.0 million are reclassified to a net margin basis in accordance with GAAP.

(b) Includes $9.5 million write-off of transition costs, net of tax benefit of $7.2 million, due to the repeal of deregulation in New Mexico, and the $10.0 million write-off related to refinancing of long-term debt, net of tax benefit of $6.6 million, reduced consolidated net earnings.

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Summarized financial information by business segment for the year ended December 31, 2002 is as follows (In thousands):

	UTILITY				
	ELECTRIC	GAS	TRANSMISSION	ELIMINATIONS	TOTAL
2002:					
Operating revenues:					
External customers	$ 646,839	$ 277,406	$ 23,150	$ –	$ 847,495
Intersegment revenues	–	–	31,950	(31,950)	–
Depreciation and amortization	69,654	20,673	8,741	–	89,068
Interest income	30,790	436	29	–	31,255
Interest charges	27,609	13,546	5,988	–	47,043
Total income tax expense (benefit)	37,482	3,755	4,475	–	45,712
Operating income	68,870	17,672	13,159	–	99,201
Segment net income	57,194	5,731	6,827	–	69,752
TOTAL ASSETS	1,442,404	563,395	224,637	–	2,230,136
GROSS PROPERTY ADDITIONS	134,483	46,676	15,472	–	196,631

	WHOLESALE	CORPORATE AND OTHER	CONSOLIDATED
2002:			
Operating revenues:			
External customers	$ 343,780	$ (72,581)(a)	$ 1,118,694
Intersegment revenues	–	–	–
Depreciation and amortization	8,808	4,533	102,409
Interest income	4,946	8,753	44,954
Interest charges	6,348	6,021	61,412
Total income tax expense (benefit)	(1,613)	(11,068)(b,c)	33,031
Operating income (loss)	3,398	(825)(b)	101,774
Segment net income (loss)	(2,461)	(3,605)(c)	63,686
TOTAL ASSETS	880,436	636,655	3,247,227
GROSS PROPERTY ADDITIONS	23,190	20,404	240,225

(a) Reflects EITF 02-3 impact, under which wholesale revenues and the associated cost of energy of $74.0 million are reclassified to a net margin basis in accordance with GAAP.

(b) Includes re-alignment costs due to the negative impact on the wholesale market uncertainty of $5.3 million, net of tax benefit of $3.5 million, and severance costs due to a workforce reduction of $0.9 million, net of tax benefit of $0.6 , which reduced consolidated operating income and net earnings.

(c) The Company recognized a $1.5 million gain, net of tax expense of $1.0 million, from the reversal of a reserve due to the successful resolution of litigation stemming from the terminated Western Resources transaction, which was offset by a $2.7 write-off, net of tax benefit of $1.9 million, of a transmission line project.

Summarized financial information by business segment for the year ended December 31, 2001 is as follows (In thousands):

	UTILITY				
	ELECTRIC	GAS	TRANSMISSION	ELIMINATIONS	TOTAL
2001:					
Operating revenues:					
External customers	$ 532,673	$ 371,265	$ 26,553	$ –	$ 930,491
Intersegment revenues	–	–	31,273	(31,273)	–
Depreciation and amortization	59,352	20,362	7,328	–	87,042
Interest income	33,751	596	24	–	34,371
Interest charges	31,828	11,807	4,582	–	48,217
Total income tax expense (benefit)	24,986	1,605	4,475	–	31,066
Operating income	62,866	14,657	12,886	–	80,409
Segment net income	38,124	2,451	6,828	–	47,403
TOTAL ASSETS	1,751,481	524,130	209,504	–	2,485,115
GROSS PROPERTY ADDITIONS	159,223	48,978	18,067	–	226,268

	WHOLESALE	CORPORATE AND OTHER	CONSOLIDATED
2001:			
Operating revenues:			
External customers	$ 1,411,500	$ (87,813)(a)	$ 2,254,178
Intersegment revenues	–	–	–
Depreciation and amortization	5,774	4,120	96,936
Interest income	5,234	9,137	48,742
Interest charges	17,063	(440)	64,840
Total income tax expense (benefit)	79,404	(29,407)(b)	81,063
Operating income	136,237	6,031	222,677
Segment net income (loss)	121,161	(18,717)(b)	149,847
TOTAL ASSETS	377,585	264,902	3,127,602
GROSS PROPERTY ADDITIONS	23,631	14,945	264,844

(a) Reflects EITF 02-3 impact, under which wholesale revenues and the associated cost of energy of $89.4 million are reclassified to a net margin basis in accordance with GAAP.

(b) Includes a Company contribution of $3.0 million, net of tax benefit of $2.0 million, to the PNM Foundation, a $7.9 million write-off, net of tax benefit of $5.1 million, of nonrecoverable coal mine decommissioning costs, the $7.8 million write-off, net of tax benefit of $5.2 million, of impaired Avistar investments, and the costs associated with the terminated acquisition of Western Resources of $10.9 million, net of tax benefit of $7.1 million, reduced consolidated net earnings.

(3) REGULATORY ASSETS AND LIABILITIES

The Company is subject to the provisions of SFAS 71 with respect to operations regulated by the PRC and the FERC. Regulatory assets represent probable future recovery of previously incurred costs, which will be collected from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are to be credited to customers through the ratemaking process. Regulatory assets and liabilities reflected in the Consolidated Balance Sheets as of December 31, relate to the following (In thousands):

	2003	2002
Assets:		
Current:		
PGAC	$ 10,416	$ 941
Gas Take-or-Pay Costs	5,020	120
SUBTOTAL	15,436	1,061
Deferred:		
Mine Reclamation Costs	92,521	100,877
Deferred Income Taxes	70,576	69,029
Financing Costs	26,368	–
Transition Costs	–	16,720
Loss on Reacquired Debt	20,936	7,345
Other	5,015	2,312
Total Deferred Assets	215,416	196,283
TOTAL ASSETS	230,852	197,344
Liabilities:		
Deferred:		
Asset retirement obligation	(27,976)	–
Deferred Income Taxes	(35,974)	(38,941)
Cost of Removal	(235,992)	(227,933)
Unrealized loss on PVNGS decommissioning trust	(6,479)	(3,813)
Gain on Reacquired Debt	(1,351)	(1,503)
PVNGS Prudence Audit	(4,306)	(4,682)
Settlement due Customers	(1,242)	(1,325)
Other	(3,064)	(1,755)
TOTAL DEFERRED LIABILITIES	(316,384)	(279,962)
NET REGULATORY LIABILITIES	$ (85,532)	$ (82,608)

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Substantially all of the Company's regulatory assets and regulatory liabilities are reflected in rates charged to customers or have been addressed in a regulatory proceeding. The Company receives or pays a rate of return on these regulatory assets and regulatory liabilities, except for mine reclamation costs, deferred income taxes, interest rate hedging costs, and unrealized loss on PVNGS decommissioning trust.

In 2001, the Company wrote off $11.1 million of regulatory assets of which $8.1 million related to non-recoverable transition costs and $3.0 million for other non-recoverable regulatory assets. See Note 13 – "Commitments and Contingencies – Global Electric Agreement" regarding 2003 write-off of transition costs.

In August 2001, the Company signed an agreement with San Juan Coal Company ("SJCC") and Tucson Electric Power Company ("Tucson") to replace two surface mining operations with a single underground mine located adjacent to the SJGS. The Company recorded a regulatory asset of $113 million for the estimated costs anticipated to close the surface mining operation. In 2001, the Company wrote off $13.0 million for the portion of coal mine decommissioning costs associated with the Company's FERC firm requirements customers and a portion of SJGS Unit 4. The Company will recover the remaining $100 million of costs associated with coal mine decommissioning that are attributed to New Mexico retail customers pursuant to its Global Electric Agreement which provides for a 17-year recovery of these costs beginning in September 2003. In 2003, the Company completed a comprehensive review of these costs and costs related to the decommissioning of the current underground mine and made adjustments to the liability and the related regulatory asset based on the resulting changes in estimate (see Note 12).

The Company is permitted, under SFAS 71, to accrue the estimated cost of removal and salvage associated with certain of its assets through depreciation expense. Cost of removal, net of salvage, allowed under rate regulations was included in accumulated depreciation. The amounts accrued in depreciation are not associated with AROs recorded in accordance with SFAS 143. With the adoption of SFAS 143, the Company has reclassified $236.0 million and $227.9 million of removal costs from accumulated depreciation to regulatory liabilities as of December 31, 2003 and 2002, respectively.

The Company accounts for its postretirement benefits other than pensions ("OPEB") costs on an accrual basis. Therefore, the Company does not defer any OPEB costs as regulatory assets.

PNM had $46.0 million of tax-exempt bonds outstanding that were callable at a premium beginning December 15, 2002, and an additional $136.0 million that became callable at a premium in August 2003. With the intention of refinancing these bonds, PNM had hedged the entire planned refinancing by entering into five forward starting interest rate swaps in the fourth quarter of 2001 and the first quarter of 2002. The Company received regulatory approval to refund the tax-exempt bonds on October 29, 2002. The refinancings were completed on May 23, 2003.

The forward starting interest rate swaps were terminated on May 13, 2003 for a cash settlement of $27.1 million. This amount has been capitalized by the Company as a financing cost and will be amortized over the life of the bonds.

Based on a current evaluation of the various factors and conditions that are expected to impact future cost recovery, the Company believes that its regulatory assets are probable of future recovery.

(4) CAPITALIZATION

Changes in common stock for PNM Resources, Inc. and Subsidiaries are as follows (Dollars in thousands):

	COMMON STOCK	
	NUMBER OF SHARES	AGGREGATE PAR VALUE
Balance at December 31, 2001	39,117,799	$ 625,632
Exercise of stock options	–	(2,412)
Tax benefit from exercise of stock options	–	899
Balance at December 31, 2002	39,117,799	624,119
Restricted stock rights	–	31
Exercise of stock options	–	(9,130)
Tax benefit from exercise of stock options	–	3,637
Pension contribution	1,121,495	28,609
ESPP purchase	19,703	456
Balance at December 31, 2003	40,258,997	$ 647,722

Common Stock

The number of authorized shares of common stock of the Holding Company is 120 million shares with no par value. The number of shares issued and outstanding was 40,258,997 and 39,117,799 as of December 31, 2003 and 2002. In 2003, the Holding Company issued 19,703 common shares for the Employee Stock Purchase Plan for $0.5 million. On June 11, 2003, a contribution of 1,121,495 Holding Company common shares

(approximately $28.6 million) was made to the Company's retirement plan (see Note 9 for further discussion). Also, $6.0 million of stock options, net of taxes, were exercised in 2003. The only change to common stock of the Holding Company in 2002 was for the exercise of stock options of $1.5 million, net of taxes.

The declaration of common dividends is dependent upon a number of factors including the ability of the Holding Company's subsidiaries to pay dividends. Currently, PNM is the Holding Company's primary source of dividends. As part of the order approving the formation of the Holding Company, the PRC placed certain restrictions on the ability of PNM to pay dividends to its parent.

The PRC order imposed the following conditions regarding dividends paid by PNM to the holding company: PNM can not pay dividends which cause its debt rating to go below investment grade; and PNM can not pay dividends in any year, as determined on a rolling four quarter basis, in excess of net earnings without prior PRC approval. In January 2003, with the signing of the Global Electric Agreement, the PRC modified the PNM dividend restriction to allow PNM to dividend earnings as well as equity contributions made by the Holding Company. Additionally, PNM has various financial covenants which limit the transfer of assets, through dividends or other means.

In addition, the ability of the Company to declare dividends is dependent upon the extent to which cash flows will support dividends, the availability of retained earnings, the financial circumstances and performance, the PRC's decisions in various regulatory cases currently pending and which may be docketed in the future, the effect of federal regulatory decisions, Congressional and legislative acts, and market economic conditions generally. Conditions imposed by the PRC on holding company formation, future growth plans and the related capital requirements and standard business considerations may also affect the Company's ability to pay dividends.

Consistent with the PRC's holding company order, PNM paid cash dividends of $49.6, $59.0 and $127.0 million to the Holding Company for the years ended December 31, 2003, 2002 and 2001 respectively.

On February 18, 2003, the Holding Company's board of directors approved a 4.5% increase in the common stock dividend. The increase raised the quarterly dividend to $0.23 per share, for an indicated annual dividend of $0.92 per share.

On February 17, 2004, the Holding Company's board of directors approved a 4.3% increase in the common stock dividend. The increase raised the quarterly dividend to $0.24 per share, for an indicated annual dividend of $0.96 per share.

Cumulative Preferred Stock

No Holding Company preferred stock is outstanding. The Holding Company's restated articles of incorporation authorize 10 million shares of preferred stock, which may be issued without restriction. The number of authorized shares of PNM cumulative preferred stock is 10 million shares. PNM has 128,000 shares, 1965 Series, 4.58%, par value of $100 per share, of cumulative preferred stock outstanding. The 1965 Series does not have a mandatory redemption requirement but may be redeemable at 102% of the par value with accrued dividends. The holders of the 1965 Series are entitled to payment before the holders of common stock in the event of any liquidation or dissolution or distribution of assets of PNM. In addition, the 1965 Series is not entitled to a sinking fund and cannot be converted into any other class of stock of PNM.

Long-Term Debt

On March 11, 1998, PNM modified its 1947 Indenture of Mortgage and Deed of Trust so that no future bonds can be issued under the mortgage. While first mortgage bonds continue to serve as collateral for Pollution Control Bonds ("PCBs") in the outstanding principal amount of $65.0 million, the lien of the mortgage covers only PNM's ownership interest in PVNGS. Senior unsecured notes ("SUNs"), which were issued under a senior unsecured note indenture, serve as collateral for PCBs in the outstanding principal amount of $520.8 million. With the exception of the $65.0 million of PCBs secured by first mortgage bonds, the SUNs are and will be the senior debt of PNM.

On May 13, 2003, the Company priced $182.0 million of tax-exempt pollution control bonds at an initial interest rate of 2.75%. The bond sale closed on May 23, 2003. By April 1, 2004, $146.0 million of bonds will need to be remarketed and $36.0 million of bonds will need to be remarketed by July 1, 2004. A portion of the proceeds were used to redeem the $46.0 million of pollution control bonds, which became callable on December 15, 2002. The remaining $136.0 million was used to redeem $136.0 million of pollution control bonds in August 2003. The Company had previously entered into various forward swaps in 2001 and 2002, to hedge the interest rate on the refinancing (see Note 6 – Fair Value of Financial Instruments – Forward Starting Interest Rate Swaps).

The premium paid to refinance the pollution control bonds was $3.6 million. The balance of the unamortized debt issuance costs associated with the pollution control bonds that were retired was $3.8 million. These amounts were capitalized as loss on reacquired debt. The portion of unamortized loss on reacquired debt associated with the FERC firm requirements customers and plant excluded from ratebase of $1.0 million was written off in conjunction with the refinancing of the pollution control bonds. The remaining balance will be amortized over the life of the new bonds and is expected to be recovered through PRC approved retail rates.

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Pursuant to PRC approval, on September 9, 2003, PNM issued and sold $300.0 million aggregate principal amount of its senior unsecured notes with a 4.40% interest rate that will mature September 15, 2008. The transaction closed on September 17, 2003 and the proceeds were used to retire $268.4 million of long-term debt with a 7.10% interest rate that would otherwise have matured in August 2005, pay the transaction costs, and improve working capital. The premium paid to refinance the long-term debt was $23.9 million of which $16.6 million was charged against earnings based on prior regulatory agreements. The remaining balance was capitalized as loss on reacquired debt and will be amortized over the life of the new debt.

On December 20, 2002, the Holding Company acquired the equity interest of the grantor trust that owns 60% of the EIP transmission line and related facilities held under an operating lease. As a result, the Company capitalized the 60% interest and $26.2 million of related debt was consolidated on the Company's balance sheet. This debt was previously disclosed and reported as an off balance sheet lease obligation. The EIP debt bore interest at the rate of 10.25%, requires semi-annual principal and interest payments and matures on April 1, 2012. On April 1, 2003, PNM exercised its early buyout option of this 60% interest and related lease. Through the exercise of the early buyout, PNM was able to retire the $26.2 million of debt. The Company will continue to exclude $4.0 million of lease obligations relating to the 40% interest that the Company does not own from the consolidated balance sheet.

Revolving Credit Facility and Other Credit Facilities

At December 31, 2003, PNM had a $300.0 million unsecured revolving credit facility (the "Facility") with an expiration date of November 21, 2006. PNM must pay commitment fees of 0.275% per year on the unused amount of the Facility. PNM must also pay a utilization fee of .125% for all borrowings in excess of 33% of the committed amount. PNM also had $23.0 million in local lines of credit. In addition, the Holding Company has a $20.0 million reciprocal borrowing agreement with PNM and $15.0 million in local lines of credit.

There were $20.0 million in outstanding borrowings bearing interest at an interest rate of 2.275% under the Facility as of December 31, 2003. On January 20, 2004, this amount was reduced to $10.0 million outstanding at an interest rate of 2.225%. PNM was in compliance with all covenants under the Facility.

Commercial Paper

On August 27, 2003, the Company entered into an unrated private issuance commercial paper program. The Company will periodically issue up to $50.0 million in unrated commercial paper for the shorter of 120 days or the maturity of the Company's Credit Facility. The commercial paper is unsecured and the proceeds were used to reduce revolving credit borrowings. The Company's Credit Facility serves as a backstop for the outstanding commercial paper. As of December 31, 2003, $50.0 million was outstanding.

Asset Securitization

On April 8, 2003, PNM entered into a transaction providing for the securitization of PNM's retail electric service accounts receivable and retail gas service accounts receivable ("AR Securitization"). The total capacity under the AR Securitization is $90.0 million. Under the AR Securitization, PNM will periodically sell its accounts receivable, principally retail receivables, to a bankruptcy remote subsidiary, PNM Receivables Corp., which in turn pledges an undivided interest in the receivables to an unaffiliated conduit commercial paper issuer. This transaction was previously approved by the PRC on December 17, 2002. As of December 31, 2003, the Company had borrowed $54.9 million under the AR Securitization, which was secured by $114.5 million of accounts receivable. PNM Receivables Corp. is consolidated in the Company's financial statements.

(5) LEASE COMMITMENTS

PNM leases interests in Units 1 and 2 of PVNGS, certain transmission facilities, office buildings and other equipment under operating leases. The lease expense for PVNGS is $66.3 million per year over base lease terms expiring in 2015 and 2016. Covenants in PNM's PVNGS Units 1 and 2 lease agreements limit PNM's ability, without consent of the owner participants in the lease transactions, (i) to enter into any merger or consolidation, or (ii) except in connection with normal dividend policy, to convey, transfer, lease or dividend more than 5% of its assets in any single transaction or series of related transactions.

In 1985 and 1986, the Company entered into a total of eleven sale and lease back transactions with owner trusts under which it sold and leased back its entire 10.2% interest in PVNGS Units 1 and 2, together with portions of the Company's undivided interest in certain PVNGS common facilities. In 1998, PNM established PVNGS Capital Trust ("Capital Trust") for the purpose of acquiring all the debt underlying the PVNGS leases. PNM consolidates Capital Trust in its consolidated financial statements. The purchase was funded with the proceeds from the issuance of $435 million of SUNS (see Note 4), which were loaned to Capital Trust. Capital Trust then acquired and holds the debt component of the PVNGS leases. For legal and regulatory reasons, the PVNGS lease payment continues to be recorded and paid gross with the debt component of the payment returned to PNM via Capital Trust. As a result, the net cash outflows for the PVNGS lease payment were $14.2, $13.2 and $12.4 million in 2003, 2002 and 2001, respectively. The summary of PNM's future minimum operating lease payments below reflects the net cash outflow related to the PVNGS leases.

PNM's other significant operating lease obligations include a leased interest in the EIP transmission line with annual lease payments of $2.9 million and a power purchase agreement for the entire output of a gas-fired generating plant in Albuquerque, New Mexico, with imputed annual lease payments of $6.0 million.

Future minimum operating lease payments (in thousands) at December 31, 2003 are:

2004	$ 29,068
2005	30,724
2006	31,542
2007	32,426
2008	33,370
Later years	268,410
TOTAL MINIMUM LEASE PAYMENTS	$ 425,540

Operating lease expense, inclusive of the net PVNGS lease payment, was approximately $33.4 million in 2003, $34.9 million in 2002 and $32.7 million in 2001. Aggregate minimum payments to be received in future periods under non-cancelable subleases are approximately $3.6 million.

6) FAIR VALUE OF FINANCIAL INSTRUMENTS

GAAP defines the fair value of a financial instrument as the amount at which the instrument could be exchanged in a current transaction between willing parties, other than in a forced sale or liquidation. Although management uses its best judgment in estimating the fair value of these financial instruments, there are inherent limitations in any estimation technique. Therefore, the fair value estimates presented herein are not necessarily indicative of the amounts that the Company could realize in a current transaction. Fair value is based on market quotes provided by the Company's investment bankers and trust advisors. The market prices used to value PNM's mark-to-market energy portfolio are based on closing exchange prices and over-the-counter quotations.

The carrying amounts reflected on the consolidated balance sheets approximate fair value for cash, temporary instruments, receivables, and payables due to the short period of maturity. The carrying amount and fair value of the Company's financial instruments (including current maturities) at December 31 are (In thousands):

	2003		2002	
	CARRYING AMOUNT	FAIR VALUE	CARRYING AMOUNT	FAIR VALUE
Long-Term Debt	$ 987,210	$ 1,029,349	$ 980,092	$ 1,027,435
Investment in PVNGS Lessors' Notes	$ 347,870	$ 424,731	$ 368,010	$ 436,345
Available for sale investments	$ 86,456	$ 86,456	$ 152,352	$ 152,352

The Company's available-for-sale securities include assets held in trust for its share of decommissioning costs of PVNGS and its executive retirement program. The trusts hold equity and fixed income securities. These amounts are included in other investments on the balance sheet. The carrying value, gross unrealized gains and losses and estimated fair value of investments in available-for-sale securities are as follows (In thousands):

	2003			
	CARRYING VALUE	UNREALIZED GAINS	UNREALIZED LOSSES	FAIR VALUE
Available-for-sale:				
Equity securities	42,269	13,893	(344)	55,818
U.S. Government securities	4,858	361	(31)	5,188
Corporate bonds	11	–	–	11
Municipal bonds	19,250	1,316	(13)	20,553
Other investments	4,895	–	(9)	4,886
	71,283	15,570	(397)	86,456

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	2002			
	CARRYING VALUE	UNREALIZED GAINS	UNREALIZED LOSSES	FAIR VALUE
Available-for-sale:				
Mortgage-backed securities	$ 32,643	$ 4,134	$ (1,514)	$ 35,263
Equity securities	33,145	410	(93)	33,462
U.S. Government securities	32,466	438	(19)	32,885
Corporate bonds	21,229	1,394	(24)	22,599
Municipal bonds	12,725	702	–	13,427
Other investments	14,716	–	–	14,716
	$ 146,924	$ 7,078	$ (1,650)	$ 152,352

At December 31, 2003, the available-for-sale securities held by the Company had the following maturities (in thousands):

	CARRYING VALUE	FAIR VALUE
Within 1 year	$ 1,513	$ 1,482
After 1 year through 5 years	2,857	2,889
After 5 years through 10 years	2,997	3,126
Over 10 years	17,024	18,518
Equity securities	52,269	55,818
Other investments	4,623	4,623
	$ 81,283	$ 86,456

The proceeds and gross realized gains and losses on the disposition of available-for-sale investments are shown in the following table. Realized gains and losses are determined by specific identification of costs of securities sold. The short-term investment balance was fully redeemed in the year ended December 31, 2003 and included in proceeds from sales (In thousands).

	2003	2002	2001
Proceeds from sales	$ 123,030	$ 219,880	$ 80,943
Gross realized gains	7,685	2,537	3,077
Gross realized losses	(5,894)	(7,624)	(7,476)

The Company uses derivative financial instruments to manage risk as it relates to changes in natural gas and electricity prices, interest rates of future debt issuances and adverse market changes for investments held by the Company's various trusts. The Company also uses certain derivative instruments for wholesale electricity sales in order to take advantage of favorable price movements and market timing activities in the wholesale power markets.

Natural Gas Contracts

Pursuant to a 1997 order issued by the New Mexico Public Utility Commission, the predecessor to the PRC, the Company is allowed to hedge certain portions of natural gas supply contracts to protect the Company's natural gas customers from the risk of adverse price fluctuations in the natural gas market. All hedge gains and losses from these hedges are recoverable through the Company's purchased gas adjustment clause ("PGAC") if deemed prudently incurred by the PRC. As a result, earnings are not affected by gains or losses generated by these instruments.

PNM purchased gas options to protect its natural gas customers from the risk of price fluctuations during the 2003-2004 heating season. PNM expended $9.5 million to purchase gas options that limit the maximum amount the Company would pay for gas during the winter heating season. The Company recovered its actual hedging expenditures as a component of the PGAC during the months of October 2003 through February 2004 in equal monthly allotments of $1.9 million.

In 2002, PNM purchased gas options to protect its natural gas customers from the risk of price fluctuation during the 2002-2003 heating season. PNM expended $6.0 million to purchase options that limit the maximum amount the Company would pay for gas during the winter heating season. The Company recovered its actual hedging expenditures as a component of the PGAC during the months of October 2002 through February 2003 in equal allotments of $1.2 million.

Electricity Contracts

The Company's wholesale operations entered into various forward physical contracts for the purchase and sale of electricity with the intent to optimize its net generation position. These contracts do not qualify for normal purchase and sale designation pursuant to SFAS 133, and are considered derivatives and marked to market as required by SFAS 133.

For the year ended December 31, 2003, the Company's Wholesale Operations settled derivative forward contracts for the sale of electricity that generated $165.9 million of electric revenues by delivering 3.5 million megawatt hours ("MWh"). The Company settled derivative forward contracts for the purchase of electricity of $157.7 million or 3.5 million MWh of electricity to support these contractual sales and other open market sales opportunities. For the year ended December 31, 2002, the Company's Wholesale Operations settled forward contracts for the sale of electricity that generated $43.9 million of electric revenues by delivering 1.2 million MWh. The Company settled derivative forward contracts for the purchase of electricity of $74.5 million or 1.4 million MWh of electricity to support these contractual sales and other open market sales opportunities. For the year ended December 31, 2001, the Company's Wholesale Operations settled derivative forward contracts for the sale of electricity that generated $77.9 million of electric revenues by delivering 2.1 million MWh. The Company settled derivative forward contracts for the purchase of electricity of $76.7 million or 1.9 million MWh of electricity to support these contractual sales and other open market sales opportunities.

As of December 31, 2003, the Company had open derivative forward contract positions to buy $30.6 million and to sell $28.6 million of electricity. At December 31, 2003, the Company had a gross mark-to-market gain (asset position) on these derivative forward contracts of $3.4 million and a gross mark-to-market loss (liability position) of $3.0 million, with a net mark-to-market gain (asset position) of $0.4 million recorded in other current assets and liabilities, respectively. The change in mark-to-market valuation is recognized in earnings each period and is recorded in operating revenues.

The Company's Wholesale Operations also entered into forward physical contracts for the sale of the Company's electric capacity in excess of its retail and wholesale firm requirement needs, including reserves. In addition, the Company entered into forward physical contracts for the purchase of retail needs, including reserves, when resource shortfalls exist. The Company generally accounts for these financial instruments as normal sales and purchases as defined by SFAS 133, as amended. From time to time the Company makes forward purchases to serve its retail needs when the cost of purchased power is less than the incremental cost of its generation. At December 31, 2003, the Company had open forward positions classified as normal sales of electricity of $236.0 million and normal purchases of electricity of $115.6 million, both of which are not recorded in the financial statements.

The Company's Wholesale Operations, including both firm commitments and other wholesale sale activities, are managed through a net asset-backed strategy, whereby the Company's aggregate net open position is covered by its own excess generation capabilities. The Company is exposed to market risk if its generation capabilities were disrupted or if its retail load requirements were greater than anticipated. If the Company were required to cover all or a portion of its net open contract position, it would have to meet its commitments through market purchases.

The Company is exposed to credit risk in the event of non-performance or non-payment by counterparties of its financial and physical derivative instruments. The Company uses a credit management process to assess and monitor the financial conditions of counterparties. The Company's credit risk with its largest counterparty as of December 31, 2003 and December 31, 2002 was $23.5 million and $18.7 million, respectively.

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(7) EARNINGS PER SHARE

In accordance with SFAS No. 128, Earnings per Share, dual presentation of basic and diluted earnings per share has been presented in the Consolidated Statements of Earnings. The following reconciliation illustrates the impact on the share amounts of potential common shares and the earnings per share amounts (In thousands, except per share amounts):

	2003	2002	2001
Basic:			
Net Earnings Before Cumulative Effect of a Change in Accounting Principle	$ 58,552	$ 63,686	$ 149,847
Cumulative Effect of a Change in Accounting Principle, net of tax of $ 23,999	36,621	–	–
Net Earnings	$ 95,173	$ 63,686	$ 149,847
Average Number of Common Shares Outstanding	39,747	39,118	39,118
Net Earnings per Share of Common Stock (Basic)	$ 2.39	$ 1.63	$ 3.83
Earnings Before Cumulative Effect of Changes in Accounting Principles	1.47	1.63	3.83
Cumulative Effect of Changes in Accounting Principles, net of tax	0.92	–	–
Net Earnings per Share of Common Stock (Basic)	$ 2.39	$ 1.63	$ 3.83
Diluted:			
Net Earnings Before Cumulative Effect of a Change in Accounting Principle	$ 58,552	$ 63,686	$ 149,847
Cumulative Effect of a Change in Accounting Principle, net of tax of $23,999	36,621	–	–
Net Earnings	$ 95,173	$ 63,686	$ 149,847
Average Number of Common Shares Outstanding	39,747	39,118	39,118
Diluted Effect of Common Stock Equivalents (a)	390	325	613
Average Common and Common Equivalent Shares Outstanding	40,137	39,443	39,731
Net Earnings per Share of Common Stock (Diluted)	$ 2.37	$ 1.61	$ 3.77
Earnings Before Cumulative Effect of Changes in Accounting Principles	1.46	1.61	3.77
Cumulative Effect of Changes in Accounting Principles, net of tax	0.91	–	–
Net Earnings per Share of Common Stock (Diluted)	$ 2.37	$ 1.61	$ 3.77

(a) Excludes the effect of average anti-dilutive common stock equivalents related to out of-the-money options of 871,493 and 1,602,277 for the years ended December 31, 2003 and 2002, respectively. There were no anti-dilutive common stock equivalents in 2001.

(8) INCOME TAXES

Income taxes before cumulative effect of changes in accounting principles consist of the following components (In thousands):

	2003	2002	2001
Current Federal income tax	$ (27,621)	$ (9,327)	$ 97,661
Current state income tax	(6,169)	(1,780)	21,220
Deferred Federal income tax	52,154	38,413	(28,967)
Deferred state income tax	12,646	8,856	(5,712)
Amortization of accumulated investment tax credits	(3,121)	(3,131)	(3,139)
TOTAL INCOME TAXES	$ 27,889	$ 33,031	$ 81,063
Charged to operating expenses	$ 28,072	$ 20,887	$ 88,769
Charged to other income and deductions	(183)	12,144	(7,706)
Total income taxes	$ 27,889	$ 33,031	$ 81,063

The Company's provision for income taxes, before cumulative effect of changes in accounting principles, differed from the Federal income tax computed at the statutory rate for each of the years shown. The differences are attributable to the following factors (In thousands):

	2003	2002	2001
Federal income tax at statutory rates	$ 30,459	$ 34,056	$ 81,024
Investment tax credits	(3,121)	(3,131)	(3,139)
Depreciation of flow-through items	2,033	2,112	2,249
Gains on the sale and leaseback of PVNGS Units 1 and 2	(527)	(527)	(527)
Equity income from passive investments	–	–	(1,180)
Annual reversal of deferred income taxes accrued at prior tax rates	(1,963)	(1,963)	(1,963)
Valuation reserve	–	–	(6,552)
Research and development credit	(966)	(551)	–
Affordable housing credit	(969)	(947)	–
Allowance for funds used during construction	(906)	–	–
State income tax	4,161	4,715	10,706
Other	(312)	(733)	445
TOTAL INCOME TAXES	$ 27,889	$ 33,031	$ 81,063
EFFECTIVE TAX RATE	32.05%	33.95%	35.02%

The components of the net accumulated deferred income tax liability were (In thousands):

	2003	2002
Deferred Tax Assets:		
Nuclear decommissioning costs	$ 32,181	$ 32,192
Regulatory liabilities related to income taxes	34,725	37,656
Minimum pension liability	49,692	56,008
Other	44,225	57,373
TOTAL DEFERRED TAX ASSETS	160,823	183,229
Deferred Tax Liabilities:		
Depreciation	(245,145)	(216,425)
Investment tax credit	(38,462)	(41,583)
Regulatory assets related to income taxes	(69,327)	(67,744)
Asset retirement obligations	(24,524)	–
Other	(71,925)	(38,792)
TOTAL DEFERRED TAX LIABILITIES	(449,383)	(364,544)
NET ACCUMULATED DEFERRED INCOME TAX LIABILITIES	$ (288,560)	$ (181,315)

The following table reconciles the change in the net accumulated deferred income tax liability to the deferred income tax expense included in the consolidated statement of earnings for the period:

Net change in deferred income tax liability per above table	$ 107,245
Change in tax effects of income tax related regulatory assets and liabilities	(4,514)
Tax effect of mark-to-market on investments available for sale	(10,863)
Tax effect of excess pension liability	(6,316)
Tax effect of cumulative effect of changes in accounting principles	(23,999)
Other	126
DEFERRED INCOME TAX EXPENSE FOR THE PERIOD	$ 61,679

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The Company has no net operating loss carryforwards as of December 31, 2003.

The Company defers investment tax credits related to rate regulated assets and amortizes them over the estimated useful lives of those assets.

All federal income tax years prior to 2000 are closed. Tax years 2000 and 2001 are currently under examination by the IRS. Although the Company does not expect any significant adjustments to the tax provision as a result of the IRS examination, management is unable to determine the final outcome of the IRS examination at this time.

There are no material differences between the provision for income taxes and deferred income taxes between the Company and PNM.

(9) PENSION AND OTHER POST-RETIREMENT BENEFITS

In 2003, the Company changed the actuarial valuation measurement date for the pension plan and other post-retirement benefits from September 30 to December 31 to better reflect the actual pension balances as of the Company's balance sheet dates and recognized a cumulative effect of a change in accounting principle of $0.8 million, net of taxes at $0.5 million (see Note 17).

Pension Plan

The Company and its subsidiaries maintain a qualified defined benefit pension plan which covers eligible union and non-union employees, including officers. The pension plan was frozen at the end of 1997 with regard to new participants. The pension plan is non-contributory and provides for benefits to be paid to eligible employees at retirement based primarily upon years of service with the Company and the average of their highest annual base salary for three consecutive years. The Company's policy is to fund actuarially-determined contributions. Contributions to the plan reflect benefits attributed to employees' years of service to date and also for services expected to be provided in the future. Pension plan assets primarily consist of common stock, fixed income securities, cash equivalents and real estate.

In December 1996, the Board of Directors approved changes to the Company's pension plan and the implementation of a 401(k) defined contribution plan effective January 1, 1998. Salaries used in pension plan benefit calculations were frozen as of December 31, 1997. Additional credited service can be accrued under the pension plan up to a limit determined by age and years of service. The Company contributions to the 401(k) plan consist of a discretionary contribution equal to 3% of eligible compensation, and a discretionary matching contribution equal to 75% of the first 6% of eligible compensation contributed by the employee on a before-tax basis. Beginning January 1, 2004, the Company will make a non-matching contribution ranging from 3% to 10% of eligible compensation based on the eligible employee's age. The Company contributed $9.0, $9.5 and $9.0 million in the years ended December 31, 2003, 2002 and 2001, respectively.

In January 2002, the Company made an aggregate contribution of $23.5 million to fund pension and other post-retirement benefit plans. An additional aggregate contribution of $1.1 million was made in September 2002 and $1.5 million in December 2002. On May 13, 2003, the board of directors approved the use of Holding Company common stock in the funding of the Company's pension plan as well as its retiree medical trust. Corporate plan sponsors may make contributions of common stock to their defined benefit plans of up to 10% of the value of the portfolio without the approval of the United States Department of Labor ("DOL") provided that the contribution does not otherwise constitute a prohibited transaction under the Employee Retirement Income Security Act ("ERISA"). On June 11, 2003, a contribution of 1,121,495 Holding Company common shares (approximately $28.9 million in market value) was made to the Company's pension plan. The Company does not plan to make any contributions in 2004 to the pension plan.

The pension plan and other post-retirement benefits have in place a policy that defines the investment objectives; establishes performance goals of the asset managers, and provides procedures for the manner in which investments are to be reviewed. The Plan implements its investments strategies to achieve the following objectives:

- Maximize the return on assets, commensurate with the risk that the Corporate Investment Committee deem appropriate to: meet the obligations of the pension plan and other post-retirement benefits; minimize the volatility of the pension expense; and account for contingencies; and
- Generate a rate of return for the total portfolio that equals or exceeds the actuarial investment rate assumption.

Management is responsible for the determination of the asset target mix and the rate of return. The Company's current target asset mix was applied to an investment consultant's asset model to determine the assumption of a 9% rate of return. The investment consultant's asset model assumption set consists of forward looking mean returns, standard deviations, and a correlation matrix for asset classes of interest to institutional clients. The investment consultant's asset model evaluates asset assumptions on an annual basis and more frequently when substantial changes in market conditions indicate.

The following sets forth the pension plan's funded status, components of pension costs and amounts (in thousands) at the pension plan measurement date of December 31, 2003 and September 30, 2002:

PENSION BENEFITS	2003	2002
Change in Projected Benefit Obligation:		
Projected benefit obligation at beginning of year	$ 426,885	$ 373,434
Service cost	5,189	5,539
Interest cost	28,089	27,238
Actuarial loss	26,166	37,632
Benefits paid	(22,535)	(20,518)
Plan change	–	3,560
PROJECTED BENEFIT OBLIGATION AT END OF PERIOD	463,794	426,885
Change in Plan Assets:		
Fair value of plan assets at beginning of year	319,113	339,838
Actual return on plan assets	80,126	(20,207)
Contributions	48,950	20,000
Benefits paid	(22,535)	(20,518)
FAIR VALUE OF PLAN ASSETS AT END OF YEAR	425,654	319,113
Funded Status	(38,140)	(107,772)
Unrecognized net actuarial loss	120,995	144,328
Unrecognized prior service cost	2,927	3,109
PREPAID PENSION COST	$ 85,782	$ 39,665

The amounts recognized in the Consolidated Balance Sheet consist of:

Prepaid benefit costs	$ 85,782	$ 39,665
Additional minimum liability	(123,922)	(147,437)
	$ (38,140)	$ (107,772)

Weighted - Average Assumptions Used to Determine Projected Benefit Obligation as of December 31, 2003 and September 30, 2002

	2003	2002
Discount rate	6.50%	6.75%
Expected return on plan assets	9.00%	9.00%

PENSION BENEFITS	2003	2002	2001
Components of Net Periodic Benefit Cost:			
Service cost	$ 5,189	$ 5,539	$ 5,544
Interest cost	28,089	27,238	25,758
Expected return on plan assets	(35,109)	(34,497)	(29,488)
Amortization of net loss (gain)	3,910	–	(847)
Amortization of transition obligation	–	–	(1,158)
Amortization of prior service cost	317	326	34
Net periodic pension benefit cost/(income)	$ 2,396	$ (1,394)	$ (157)

Weighted - Average Assumptions Used to Determine Net Periodic Benefit Cost as of December 31, 2003 and September 30, 2002 and 2001

	2003	2002	2001
Discount rate	6.75%	7.50%	8.25%
Expected return on plan assets	9.00%	9.00%	7.750%
Rate of compensation increase	N/A	N/A	N/A

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The following table outlines the asset allocation for the pension plan as of December 31:

	2003	2002
Equity securities	65%	61%
Debt securities	25%	29%
Real estate	8%	10%
Other	2%	–

The pension plan is currently targeting the following asset allocation for 2004:

Domestic Equity	47.5%
Non-US Equity	10.0%
Fixed Income	22.5%
Real Estate	5.0%
Private Equity	5.0%
Absolute Return	10.0%

Other Post-Retirement Benefits

The Company provides medical and dental benefits to eligible retirees. Currently, retirees are offered the same benefits as active employees after taking Medicare into consideration. The following sets forth the other post-retirement benefits' funded status, components of net periodic benefit cost (in thousands) at the measurement date of December 31, 2003 and September 30, 2002:

	OTHER BENEFITS	
	2003	2002
Change in Benefit Obligation:		
Benefit obligation at beginning of year	$ 117,796	$ 109,408
Service cost	3,086	2,694
Interest cost	7,840	8,082
Plan participant's contributions	1,534	795
Amendments	(18,720)	(31,960)
Unrecognized actuarial loss	10,187	32,623
Expected benefit paid	(6,911)	(3,846)
BENEFIT OBLIGATION AT END OF PERIOD	114,812	117,796
Change in Plan Assets:		
Fair value of plan assets at beginning of year	37,387	40,594
Actual return on plan assets	11,055	(6,478)
Employer contribution	7,892	6,322
Participant contribution	1,534	795
Benefits paid	(6,911)	(3,846)
Fair value of plan assets at end of year	50,957	37,387
Funded Status	(63,855)	(80,409)
Employer contribution after measurement date	–	1,538
Unrecognized net transition obligation	16,354	18,171
Unrecognized net actuarial loss	72,987	74,048
Unrecognized prior service cost	(48,087)	(31,960)
ACCRUED POST-RETIREMENT COSTS	$ (22,601)	$ (18,612)

Weighted – Average Assumptions Used to Determine Projected Benefit Obligation as of December 31, 2003 and September 30, 2002

	2003	2002
Discount rate	6.50%	6.75%
Expected return on plan assets	9.00%	9.00%

	OTHER BENEFITS		
	2003	2002	2001
Components of Net Periodic Benefit Cost:			
Service cost	$ 3,086	$ 2,694	$ 2,844
Interest cost	7,840	8,082	7,906
Expected return on plan assets	(4,592)	(4,505)	(3,412)
Prior service cost amortization	(2,593)	–	–
Amortization of net loss	4,124	1,320	799
Amortization of transition obligation	1,817	1,817	1,817
NET PERIODIC POST-RETIREMENT BENEFIT COST	$ 9,682	$ 9,408	$ 9,754

Weighted - Average Assumptions Used to Determine Net Periodic Benefit Cost as of December 31, 2003 and September 30, 2002 and 2001

	2003	2002	2001
Discount rate	6.75%	7.50%	8.25%
Expected return on plan assets:			
401 (h) and union VEBA	9.00%	9.00%	7.75%
Non-union VEBA	9.00%	7.50%	6.25%
Rate of compensation increase	N/A	N/A	N/A

In 2003, the other post-retirement benefits plan was amended to reflect the changes to the benefit coverage provided to both current and future retirees. In 2002, the other post-retirement benefits plan was amended to reflect the charge in cost-sharing provisions of the retiree's contribution made toward medical costs and the elimination of a tobacco surcharge.

The effect of a 1% increase in the health care trend rate assumption would increase the accumulated post-retirement benefit obligation as of December 31, 2003, by approximately $9.2 million and the aggregate service and interest cost components of net periodic post-retirement benefit cost for 2003 by approximately $2.2 million. The health care cost trend rate is expected to decrease to 6.0% by 2010 and to remain at that level thereafter.

The following table outlines the asset allocation for the other post-retirement benefits as of December 31:

	2003	2002
Equity securities	43%	100%
Debt securities	57%	–

The Company is currently targeting an asset allocation of 50% equity securities and 50% debt securities in 2004.

Executive Retirement Program

The Company has an executive retirement program for a group of management employees. The program was intended to attract, motivate and retain key management employees. The Company's projected benefit obligation for this program, as of the plan measurement date of December 31, 2003 and 2002, was $19.9 million and $19.0 million, respectively. As of December 31, 2003 and 2002, the Company has recognized an additional minimum liability of $4.7 million and $4.1 million, respectively, for the amount of unfunded accumulated benefits in excess of accrued pension costs. The net periodic cost for 2003, 2002 and 2001 was $1.6 million, $1.7 million and $1.7 million, respectively. In 1989, the Company established an irrevocable grantor trust in connection with the executive retirement program. Under the terms of the trust, the Company may, but is not obligated to, provide funds to the trust, which was established with an independent trustee, to aid it in meeting its obligations under the program. Marketable securities in the amount of approximately $6.9 million (fair market value of $7.8 million) are presently in the trust. No additional funds have been provided to the trust since 1989.

(10) STOCK-BASED COMPENSATION PLANS

The Company's Performance Stock Plan ("PSP") expired on December 31, 2000. The PSP was a non-qualified stock option plan, covering a group of management employees. Options to purchase shares of the Holding Company's common stock were granted at the fair market value of the shares at the close of business on the date of the grant. Options granted through December 31, 1995 vested on June 30, 1996 and have an exercise term of up to 10 years. All subsequent awards granted between December 31, 1995 and February 2000, vest three years from the grant date of the awards. All options vest upon death, disability, retirement, impaction or involuntary termination other than for cause. Awards granted in December 2000 vest ratably over three years on the anniversary of the grant date. The maximum number of options authorized that could be granted through

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December 31, 2000 was 5.0 million shares of Holding Company common stock. Although the authority to grant options under the PSP expired on December 31, 2000, the options that were granted continue to be effective according to their terms.

A new employee stock incentive plan, the Omnibus Performance Equity Plan ("PEP"), became effective with the formation of the Holding Company on December 31, 2001. The PEP provides for the granting of non-qualified stock options, incentive stock options, restricted stock rights, performance shares, performance units and stock appreciation rights to officers and key employees. The total number of shares of Holding Company common stock subject to all awards under the PEP may not exceed 2.5 million, subject to adjustment under certain circumstances defined in the PEP. The number of shares of Holding Company common stock subject to the grant of restricted stock rights, performance shares and units and stock appreciation rights is limited to 500,000 shares. Re-pricing of stock options is prohibited unless specific shareholder approval is obtained. In 2003, 811,900 options were awarded. Under the PEP, 47,157 options were exercised in 2003. The number of options and restricted stock rights outstanding as of December 31, 2003 were 1,586,409 and 1,620, respectively.

Stock options may also be provided to non-employee directors of the Company under the Company's Director Retainer Plan ("DRP"). The number of options granted in 2003 under the DRP was 40,000 shares with an exercise price of $24.07 and 10,000 shares with an exercise price of $25.90. Under the DRP plan, vesting occurs on the date of the next annual meeting after the award. Under the DRP 1,500 options were exercised in 2003, 4,000 in 2002 and 4,000 in 2001. The number of options outstanding as of December 31, 2003, was 121,500. Restricted stock issuances were based on the fair market value of the Company's common stock at the close of business on the date of grant and vest ratably three years on the anniversary of the grant date. Amendments to the DRP were approved by the shareholders on July 3, 2001 and the amended plan became the DRP for the new Holding Company on December 31, 2001. Under the DRP, the maximum number of authorized shares was 200,000 (including shares previously granted) through July 1, 2005. The annual retainer is payable in cash and stock options. The exercise price of stock options granted under the DRP is determined by the fair market value of the stock at the close of business on the grant date.

All stock incentives (options, restricted stock and performance shares) issued to employees are awarded under the initial amount of shares authorized according to the PEP and DRP plan. Exercised stock options are purchased and sold on the open-market on the date of exercise.

A summary of the status of the Company's stock option plans at December 31, and changes during the years then ended is presented below.

	2003		2002		2001	
FIXED OPTIONS	SHARES	WEIGHTED AVERAGE EXERCISE PRICE	SHARES	WEIGHTED AVERAGE EXERCISE PRICE	SHARES	WEIGHTED AVERAGE EXERCISE PRICE
Outstanding at beginning of year	3,510,622	$ 20.906	2,981,301	$ 19.100	3,336,221	$19.120
Granted	861,900	$19.833	901,620	$25.745	6,000	$22.610
Exercised	1,057,725	$17.578	356,132	$18.044	299,951	$19.610
Forfeited	24,451	$19.963	16,167	$21.390	60,969	$17.961
Outstanding at end of year	3,290,346		3,510,622		2,981,301	
Options exercisable at year-end	1,528,749		1,525,345		981,197	
Options available for future grant	890,471		1,777,880		2,500,000	

The following table summarizes information about stock options outstanding at December 31, 2003:

	OPTIONS OUTSTANDING			OPTIONS EXERCISABLE	
RANGE OF EXERCISE PRICES	NUMBER OUTSTANDING AT 12/31/03	WEIGHTED AVERAGE REMAINING CONTRACTUAL LIFE	WEIGHTED AVERAGE EXERCISE PRICES	NUMBER EXERCISABLE AT 12/31/03	WEIGHTED AVERAGE EXERCISE PRICES
DRP $ 0 - $27.35	121,500	4.07 years	$ 21.152	76,835	$19.016
PSP $11.50 - $24.313	1,580,817	5.56 years	$ 20.724	1,227,959	$21.039
PEP $ 0 - $28.22	1,588,029	8.45 years	$ 22.665	223,955	$25.803
	3,290,346	7.02 years	$21.676	1,528,749	$21.635

The following table summarizes weighted-average fair value of options granted during the year:

	2003	2002	2001
PEP	$ 4.91	$ 7.42	$ –
DRP	$ 5.14	$ 7.03	$ 13.94
Total fair market value of all options granted (in thousands)	$ 1,414	$ 6,677	$ 83

The fair value of each option grant is determined on the date of grant using the Black-Scholes option-pricing model with the following weighted-average assumptions:

	2003	2002	2001
Dividend yield	5.88%	3.43%	3.10%
Expected volatility	45.49%	33.62%	33.99%
Risk-free interest rates	4.00%	4.87%	5.38%
Expected life	10.0 years	10.0 years	10.0 years

(11) CONSTRUCTION PROGRAM AND JOINTLY-OWNED PLANTS

The Company's construction expenditures for 2003 were approximately $177.2 million, including expenditures on jointly-owned projects. The Company's proportionate share of operating and maintenance expenses for the jointly-owned plants is included in operating expenses in the consolidated statements of earnings.

At December 31, 2003, the Company's interests and investments in jointly-owned generating facilities are (In thousands):

STATION (FUEL TYPE)	PLANT IN SERVICE	ACCUMULATED DEPRECIATION	WORK IN PROGRESS	CONSTRUCTION COMPOSITE INTEREST
San Juan Generating Station (Coal)	$ 693,524	$ 362,864	$ 4,897	46.30%
Palo Verde Nuclear Generating Station (Nuclear)*	$ 238,168	$ 62,138	$ 18,787	10.20%
Four Corners Power Plant Units 4 and 5 (Coal)	$ 120,593	$ 86,079	$ 5,436	13.00%

* Includes the Company's interest in PVNGS Unit 3, the Company's interest in common facilities for all PVNGS units and the Company's owned interests in PVNGS Units 1 and 2.

San Juan Generating Station ("SJGS")

The Company operates and jointly owns SJGS. At December 31, 2003, SJGS Units 1 and 2 are owned on a 50% shared basis with Tucson Electric Power Company, Unit 3 is owned 50% by the Company, 41.8% by Southern California Public Power Authority ("SCPPA") and 8.2% by Tri-State Generation and Transmission Association, Inc. Unit 4 is owned 38.457% by the Company, 28.8% by M-S-R Public Power Agency, ("M-S-R"), 10.04% by the City of Anaheim, California, 8.475% by the City of Farmington, 7.2% by the County of Los Alamos, and 7.028% by Utah Associated Municipal Power Systems.

Palo Verde Nuclear Generating Station ("PVNGS")

The Company is a participant in the three 1,270 MW units of PVNGS, also known as the Arizona Nuclear Power Project, with Arizona Public Service Company ("APS") (the operating agent), Salt River Project, El Paso Electric Company ("El Paso"), Southern California Edison Company, SCPPA and The Department of Water and Power of the City of Los Angeles. The Company has a 10.2% undivided interest in PVNGS, with portions of its interests in Units 1 and 2 held under leases. (See Note 12 for additional discussion.)

Four Corners Power Plant ("Four Corners")

The Company is a participant in two 755 MW units of Four Corners with APS (the operating agent), El Paso, Salt River Project, Southern California Edison Company, and Tucson Electric Power Company. The Company has a 13% undivided interest in Units 4 and 5 of Four Corners.

(12) ASSET RETIREMENT OBLIGATIONS

The Company identified the asset retirement obligation ("ARO") liability on the decommissioning of the Company's nuclear generation facilities and fossil fuel generation plants. The Company's transmission and distribution facilities are also subject to SFAS 143. The majority of these assets, however, have an indeterminable useful life and settlement date. As such, an ARO liability for transmission and distribution assets would not be recognized until a reasonable estimate of the fair value of these assets can be made and a settlement date becomes known. In 2003, the Company did not identify any material AROs associated with the transmission and distribution assets.

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Previously, the Company had recognized decommissioning costs for its fossil fuel and nuclear generation facilities ratably over approved cost recovery periods. Upon implementation of SFAS 143 the net difference between the amounts determined to represent legal AROs under SFAS 143 and the Company's previous method of accounting for decommissioning costs, has been recognized as a cumulative effect of a change in accounting principle, net of related income taxes (see Note 17). Additionally, certain amounts accrued for nuclear decommissioning costs over the Company's legal AROs for its nuclear generation facilities have been reclassified as regulatory liabilities.

The effects of adoption of SFAS 143 standard are based on the Company's interpretation of the standard and determination of underlying assumptions, such as the Company's discount rate, estimates of the future costs for decommissioning and the timing of the removal activities to be performed. Any changes in these assumptions underlying the required calculations may require revisions to the estimated ARO when identified.

A reconciliation of the Company's asset retirement obligations is as follows (In thousands):

	DECEMBER 31, 2003
Upon adoption at January 1, 2003	$ 42,201
Liabilities incurred	623
Liabilities settled	–
Accretion expense	3,592
Revisions to estimate	–
	$ 46,416

(13) COMMITMENTS AND CONTINGENCIES

Long-Term Power Contracts

PNM has a power purchase contract with Southwestern Public Service Company ("SPS"), which originally provided for the purchase of up to 200 MW, expiring in May 2011. PNM may reduce its purchases from SPS by 25 MW annually upon three years' notice. PNM provided such notice to reduce the purchase by 25 MW in 1999 and by an additional 25 MW in 2000. PNM also is party to a master power purchase and sale agreement with SPS, dated August 2, 1999, pursuant to which PNM has agreed to purchase 72 MW of firm power from SPS from 2002 through 2005. Beginning May 2004, PNM will purchase an additional 45 MW of firm energy through 2005, increasing to 67 MW in 2006. PNM has 70 MW of contingent capacity obtained from El Paso under a transmission capacity for generation capacity trade arrangement through September 2004. Beginning October 2004 and continuing through June 2005, the capacity amount is 39 MW. PNM holds a purchased power agreement ("PPA") with Tri-State for 50 MW through June 30, 2010. In addition, PNM is interconnected with various utilities for economy interchanges and mutual assistance in emergencies.

In 1996, PNM entered into an operating lease for the rights to all the output of a new gas-fired generating plant for 20 years. The operating lease's maximum dependable capacity is 132 MW. In July 2000, the plant went into operation. The gas turbine generating unit is operated by Delta-Person Limited Partnership ("Delta") and is located on PNM 's retired Person Generating Station site in Albuquerque, New Mexico. Primary fuel for the gas turbine generating unit is natural gas, which is procured by Wholesale on the open market and delivered by Gas through its transportation services. In addition, the unit has the capability to utilize low sulfur fuel oil in the event natural gas is not available or cost effective.

In July 2001, PNM entered into a long-term wholesale power contract with Texas-New Mexico Power ("TNP") to provide power to serve a portion of TNP's New Mexico retail load. The contract, which commenced July 1, 2001, expires December 31, 2006. PNM provided varying amounts of firm power on demand to complement existing contracts for the first two years of the agreement. As those contracts expired at the end of 2002, PNM became TNP's sole supplier for its load in New Mexico. In the last year of the contract, it is estimated that TNP will need 114 MW of firm power.

In December 2002, PNM entered into a 27 month contract to supply 80 MW of power to U.S. Navy facilities in San Diego, California. PNM began delivering power under the contract January 1, 2003. The contract runs through March 2005.

In 2002, PNM entered into an agreement with FPL Energy LLC ("FPL"), a subsidiary of FPL Group, Inc., to develop a 200 MW wind generation facility in New Mexico. PNM began receiving commercial power from the project in June 2003. FPL Energy owns and operates the New Mexico Wind Energy Center ("NMWE"), which consists of 136 wind-powered turbines on a site in eastern New Mexico. PNM has a contract to purchase all the power generated by the NMWE for 25 years. In 2003, PNM received approval from the PRC for a voluntary tariff that allows PNM retail customers to buy wind-generated electricity for a small monthly premium. Power from the facility not subscribed by PNM retail customers under the voluntary program is sold on the wholesale market, either within New Mexico or outside the state.

PNM successfully completed a number of long-term contracts during 2003. In September 2003, PNM entered into a long-term contract to supply between 15 and 25 MW of power to Overton Power District Number 5 in Southern Nevada. The contract began October 1, 2003 and runs through December 31, 2007. In October of 2003, PNM completed a five-year contract to sell Salt River 50 megawatts of wind power and associated renewable energy credits from the NMWE for the third quarter of each year from 2004 through 2008. In December 2003, PNM completed an agreement to supply up to 35 megawatts of power to the Mesa, Arizona, municipal utility. PNM is replacing Ohio-based American Electric Power (AEP) as supplier under a contract that runs through 2013.

Coal Supply

The coal requirements for the SJGS are being supplied by San Juan Coal Company ("SJCC"), a wholly-owned subsidiary of BHP Billiton. SJCC holds certain Federal, state and private coal leases under an underground coal sales agreement ("coal agreement") pursuant to which it will supply processed coal for operation of the SJGS until 2017. The coal agreement is a cost plus contract. SJCC is reimbursed for all costs for mining and delivering the coal plus an allocated portion of administrative costs. In addition, SJCC receives a return on its investment. BHP Minerals International, Inc. has guaranteed the obligations of SJCC under the coal agreement. This guarantee is with respect to SJCC's obligations as defined in the coal agreement and protects against contingencies such as SJCC non-performance, insolvency, bankruptcy, reorganization, dissolution, and other corporate or organizational adversities. The coal agreement contemplates the delivery of approximately 91 million tons of coal during its remaining term. That amount would supply substantially all the requirements of the SJGS through approximately 2017.

In August 2001, the Company and Tucson Electric Power Company ("Tucson") signed the coal agreement with SJCC to replace two surface mining operations with a single underground mine located adjacent to the plant. The initial development of the underground mine began in the fourth quarter of 2000. After the longwall equipment became operational in October 2002, the mine was expected to achieve full station supply in March of 2003. It did not achieve this production level until December 2003, necessitating partial coal supply from existing inventory. Despite geological issues that impeded the underground mine production rates and efficiencies that were expected, SJGS fuel costs declined by 3.5% between 2002 and 2003. SJCC and the Company continually review coal cost projections and work with the Company's mine consultants to incorporate the experience gained from the first full year mining operations.

Four Corners Power Plant ("Four Corners") is supplied with coal under a fuel agreement between the owners and BHP Navajo Coal Company ("BNCC"), under which BNCC agreed to supply all the coal requirements for the life of the plant. The current fuel agreement which has been recently extended, expires July 6, 2016. The extension of the agreement did not materially affect the coal cost forecast. BNCC holds a long-term coal mining lease, with options for renewal, from the Navajo Nation and operates a surface mine adjacent to Four Corners with the coal supply expected to be sufficient to supply the units for their estimated useful lives.

In connection with both the SJGS coal agreement and the Four Corners fuel agreement, the owners are required to reimburse SJCC and BNCC for the cost of coal mine decommissioning or reclamation. Final mine reclamation occurs when mining production activities conclude. The Company considers these costs part of the cost of delivered coal costs over the life of the respective mine. This liability is recorded at estimated fair value based on the expected cash out-flows to be made to reimburse SJCC and BNCC for their reclamation activities. These cash flows are discounted at a credit adjusted risk-free rate. The liability is accreted and an appropriate incremental cost is recognized using the interest method.

In 2003, the Company completed a comprehensive review with the help of an outside consulting firm of the final reclamation costs for both the surface mines that previously provided coal to SJGS and the current underground mine providing coal. Based on this study, the Company revised its estimates of the final reclamation of the surface mine. In addition, the mining contract with BNCC supplying Four Corners was renewed until 2016. Previously the Company had recognized obligations related to these surface mines of $113.9 million. Based on these changes in estimate, the final cost of reclamation is expected to be $139.3 million in accreted dollars. In 2002 and 2003, the Company made payments of $36.6 million and $12.9 million, respectively, against this liability. As of December 31, 2003, $56.9 million was recognized as the Company's obligation for reclamation using the fair value method to determine the liability.

In the Global Electric Agreement (see "Global Electric Agreement" below), the Company was allowed to collect $100 million of surface mine final reclamation costs over the next 17 years. The Company expects to recover the remaining amount in a future rate case. In addition, the Company expects to recover the portion of final underground mine reclamation costs related to New Mexico ratepayers in future rate cases.

The underground mine began commercial operation in January 2003. The Company recognized a reclamation liability of $0.6 million related to mining activities in 2003.

Natural Gas Supply

The Company contracts for the purchase of gas to serve its retail customers. These contracts are short-term in nature supplying the gas needs for the current heating season and the following off-season months. The price of gas is a pass-through, whereby the Company recovers 100% of its cost of gas.

The natural gas used as fuel by Electric and Wholesale was delivered by Gas. In the second quarter of 2001, Electric and Wholesale began procuring its gas supply independent of the Company and contracting with Gas for transportation services only.

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Steam Generator Tubes

APS, as the operating agent of PVNGS, has encountered tube cracking in the steam generators and has taken, and will continue to take, remedial actions that it believes have slowed the rate of tube degradation. The projected service life of steam generators is assessed on an on-going basis. Two replacement steam generators were installed in Unit 2 during its Fall 2003 refueling outage. The Company's share of the fabrication and installation costs were approximately $24.7 million as of December 31, 2003.

The PVNGS participants ("Participants") have approved the purchase of replacement steam generators for Units 1 and 3. Preliminary work for the installation of the replacement steam generators has also been approved by the Participants. These actions will provide the Participants with options regarding the replacement of steam generators in Unit 1 and Unit 3. Unit 1 could be replaced as early as Fall 2005, should the Participants choose to do so. The Company estimates that its portion of the fabrication and installation costs and associated power upgrade modifications for Units 1 and 3, will be approximately $46 million over the period 2002-2008 (exclusive of replacement power costs), should installation of the ordered replacement steam generators be approved.

PVNGS Decommissioning Funding

PNM has a program for funding its share of decommissioning costs for PVNGS. The nuclear decommissioning funding program is invested in equities and fixed income instruments in qualified and non-qualified trusts. The results of the 2001 decommissioning cost study indicated that PNM's share of the PVNGS decommissioning costs, excluding spent fuel disposal, would be approximately $201 million (measured in 2001 dollars).

PNM provided an additional $3.1 million, $10.7 million and $6.1 million funding for the year ended December 31, 2003, 2002 and 2001, respectively, into the qualified and non-qualified trust funds. The estimated market value of the trusts for the year ended December 31, 2003 was approximately $78.7 million.

Nuclear Spent Fuel and Waste Disposal

Pursuant to the Nuclear Waste Policy Act of 1982, as amended in 1987 (the "Waste Act"), the United States Department of Energy ("DOE") is obligated to accept and dispose of all spent nuclear fuel and other high-level radioactive wastes generated by domestic power reactors. Under the Waste Act, the DOE was to develop facilities necessary for the storage and disposal of spent nuclear fuel and to have the first facility in operation by 1998. The DOE has announced that such a repository cannot be completed before 2010.

The operator of PVNGS has fuel storage pools at PVNGS, which accommodates fuel from normal operation of PVNGS. To continue to allow full core offload capability, older fuel is being placed in dry storage casks and removed from the Units. Through December 31, 2003, the operator of PVNGS has loaded 10 dry storage casks and placed the casks in the completed dry storage facility. Fuel from Unit 3 will be removed from the Unit 3 fuel storage pool during the first quarter of 2004. PNM currently estimates that it will incur approximately $41.0 million (in 2001 dollars) over the life of PVNGS for its share of the fuel costs related to the on-site interim storage of spent nuclear fuel during the operating life of the plant. PNM accrues these costs as a component of fuel expense, meaning that the charges are accrued as the fuel is burned. The Company has accrued $1.0 million in each of 2003 and 2002 for interim storage costs. The operator of PVNGS currently believes that spent fuel storage or disposal methods will be available for use by PVNGS to allow its continued operation. The dry storage facility has the space to hold all fuel anticipated to be used during the licensed life of PVNGS.

PVNGS Liability and Insurance Matters

The Participants have financial protection for public liability resulting from nuclear energy hazards to the full limit of liability under federal law. This potential liability is covered by primary liability insurance provided by commercial insurance carriers in the amount of $300.0 million and the balance by an industry-wide retrospective assessment program. If losses at any nuclear power plant covered by the programs exceed the primary liability insurance limit, the Company could be assessed retrospective adjustments. Effective August 20, 2003, the maximum assessment per reactor under the program for each nuclear incident increases from approximately $88 million to approximately $101 million. The retrospective assessment is subject to an annual limit of $10.0 million per reactor per incident. Based upon the Company's 10.2% interest in the three PVNGS units, the Company's maximum potential assessment per incident for all three units is approximately $31 million, with an annual payment limitation of approximately $3 million per incident. If the funds provided by this retrospective assessment program prove to be insufficient, Congress could impose revenue-raising measures on the nuclear industry to pay claims.

Possible Price-Anderson Act Changes

Versions of comprehensive energy bills proposed for adoption by Congress contain provisions that would amend Federal Law (the "Price-Anderson Act") addressing public liability from nuclear energy hazards in ways that would increase the annual limit on retrospective assessments (see "PVNGS Liability and Insurance Matters" above) from $10.0 million to $15.0 million per reactor per incident with the Company's annual exposure per incident increasing from approximately $3.0 million to $4.5 million.

The Company believes that such changes in applicable law, if enacted, would not result in a "deemed loss event" being declared by the equity investors in respect of the Company's sale and leaseback transactions of PVNGS Units 1 and 2.

Global Electric Agreement

On October 10, 2002, PNM announced that it had agreed with the PRC staff, the New Mexico Attorney General ("AG"), and other consumer groups on a Global Electric Agreement that provided for joint support for the repeal of a majority of the New Mexico Electric Utility Industry Restructuring Act of 1999, as amended ("Restructuring Act"), a fixed rate path, procedures for the Company's participation in unregulated generating plant activities and other regulatory issues. The ratepath is effective for services rendered September 1, 2003 through December 31, 2007. Based on the normal time frame for rate proceedings in New Mexico of ten months, a change in rates would not happen until late 2008. The Global Electric Agreement was approved by the PRC in January 2003. Legislation repealing the Restructuring Act and continuing the authorization for utilities to participate in unregulated generating plant activities for a limited time according to the Global Electric Agreement was passed by the New Mexico Legislature and signed into law by the Governor on April 8, 2003. In the Global Electric Agreement, PNM agreed to forego recovery of the costs incurred in preparing to transition to a competitive retail market in New Mexico under the repealed law. This resulted in a charge of $16.7 million, pre-tax, in the first quarter of 2003. As a result of the repeal of the Restructuring Act, PNM has re-applied the accounting requirements of SFAS 71 to its regulated generation activities effective January 2003, which did not have a material effect on the Company's financial condition or results of operations.

Gas Rate Case

On January 10, 2003, PNM filed a general gas rate case, requesting that the PRC approve an increase in the service fees charged to its 441,000 natural-gas customers. PNM's proposal would have increased both the set monthly service fee and the charge tied to monthly usage. Such fees are separate from the cost of gas charged to customers. The monthly cost of gas charge would not be affected by the fee increase.

On June 25, 2003, PNM, the PRC Staff, and a group of industrial consumers filed a settlement allowing the Company a $20.0 million annual revenue increase in base cost of service rates, a $1.6 million annual increase in miscellaneous fees and charges and the recovery of $4.4 million in previously approved costs. The settlement rates were proposed to go into effect for bills rendered in November 2003. A final order disapproving the settlement was issued on November 3, 2003.

The Company successfully sought rehearing of the final order disapproving the stipulation. In its request for rehearing, the Company proposed two alternatives for delaying the residential rate increase. The rehearing was held on November 25, 2003. As a result of the rehearing, the PRC in January 2004 unanimously approved the stipulation. Under the stipulation, the residential rate increase will go into effect with bills rendered in April 2004. The approved rates will increase gas revenues approximately $22.0 million annually. The Company will forego the recovery of any revenue lost as a result of the delay. All other rate increases go into effect with the first billing cycle after the date of the final order approving the amended stipulation, January 13, 2004.

Water Supply

Because of New Mexico's arid climate and current drought conditions, there is a growing concern in New Mexico about the use of water for power plants. The availability of sufficient water supplies to meet all the needs of the state, including growth, is a major issue. The Company has secured water rights in connection with the Afton and Lordsburg plants and water availability does not appear to be an issue for these plants at this time.

The Four Corners region, in which SJGS and Four Corners are located, has been experiencing drought conditions that may affect the water supply for the Company's generation plants. If adequate precipitation is not received in the watershed that supplies the Four Corners areas, the plants may be affected in 2004 and the future. The United States Bureau of Reclamation ("USBR") has been requested to approve a supplemental contract for 8,300 acre feet per year for a one-year term ending December 31, 2004. Environmental approvals are also in the process of being obtained for the supplemental contract. PNM has also signed a voluntary shortage sharing agreement with tribes and other water users in the San Juan Basin for a one-year term ending December 31, 2004. Environmental approvals for that agreement are pending. A similar agreement was entered into in 2003. Although PNM does not believe that its operations will be materially affected by the drought conditions at this time, it cannot forecast the weather situation or its ramifications, or how regulations and legislation may impact PNM's situation in the future, should the drought continue.

Western United States Wholesale Power Market

Various circumstances, including electric power supply shortages, weather conditions, gas supply costs, transmission constraints, and alleged market manipulation by certain sellers, resulted in the well-publicized "California energy crisis" and in the bankruptcy filings of the California Power Exchange ("Cal PX") and of Pacific Gas and Electric Company ("PG&E"). However, since the third quarter of 2001, conditions in the Western wholesale power market have changed substantially because of regulatory actions, conservation measures, the construction of additional generation, a decline in natural gas prices relative to levels reached during the California energy crisis and regional economic conditions.

As a result of the foregoing conditions in the Western market, the FERC and other federal and state governmental authorities are conducting investigations and other proceedings relevant to the Company and other sellers. The more significant of these in relation to the Company are summarized below.

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California Refund Proceeding

San Diego Gas and Electric Company ("SDG&E") and other California buyers have filed a complaint with the FERC against sellers into the California wholesale electric market. Hearings were held in September 2002, and the administrative law judge ("ALJ") issued the "Proposed Findings on California Refund Liability" in December 2002, in which it was determined that the Cal ISO had, for the most part, correctly calculated the amounts of the potential refunds owed by sellers. The ALJ identified what were termed "ballpark" figures for the amount of refunds due under the order in an appendix to the proposed findings document. PNM was identified as having a refund liability of approximately $4.3 million, while being owed approximately $7 million from the Cal ISO. Pursuant to the FERC's order, PNM filed, in conjunction with the competitive supplier group, initial comments in January 2003 to the ALJ's preliminary findings addressing errors the Company believes the ALJ made in the proposed findings, and filed reply comments in February 2003.

Prior to the December 2002 ALJ decision, the Ninth Circuit Court of Appeals ordered the FERC to allow the parties in the case to provide additional evidence regarding alleged market manipulation by sellers. Several California parties submitted additional evidence in March 2003 to support their position that virtually all market participants, including PNM, either engaged in specific market manipulation strategies or facilitated such strategies. PNM maintains that it did not engage in improper wholesale activities, and filed reply evidence in March 2003, denying the allegations against it.

In March 2003, the FERC issued an order substantially adopting the ALJ's findings in his December 2002 decision, but requiring a change to the formula used to calculate refunds. The FERC raised concerns that the indices for California gas prices, a major element in the formula, had been subject to potential manipulation and were unverifiable. The effect of this change, which is not yet final, would be to increase PNM's refund liability. In October 2003, the FERC issued its order on rehearing in which it affirmed its decision to change the gas price indices used to calculate the refund amounts. This has the effect of increasing the Company's amount of refund. The precise amounts, however, will not be certain until the Cal ISO and Cal PX recalculate refund amounts which FERC required that they do as soon as possible, but no later than five months after its October 2003 Order. The Company is currently awaiting the filing of additional refund information by the Cal ISO and Cal PX and is unable to predict the ultimate outcome of this FERC proceeding, or whether PNM will be directed to make any refunds as the result of the FERC order.

Pacific Northwest Refund Proceeding

In addition to the California refund proceedings, Puget Sound Energy, Inc. filed a complaint at the FERC alleging that spot market prices in the Pacific Northwest wholesale electric market were unjust and unreasonable. In September 2001, the ALJ issued a recommended decision and declined to order refunds associated with wholesale electric sales in the Pacific Northwest. In a ruling similar to the one issued in the California refund proceeding, the FERC allowed additional discovery to take place and the submission of additional evidence in the case in March 2003. In June 2003, the FERC issued an order terminating the proceeding and adopting the ALJ's recommendation that no refunds should be ordered. Several parties in the proceeding filed requests for rehearing and in November 2003, FERC denied rehearing and reaffirmed its prior ruling that refunds were not appropriate for spot market sales in the Pacific Northwest during the first half of 2001. In November 2003, the Port of Seattle filed an appeal of FERC's order denying rehearing in the Ninth Circuit Court of Appeals. As a participant in the proceedings before FERC, the Company is also participating in the appeal proceedings. The Company is unable to predict the ultimate outcome of this appeal, or whether PNM will ultimately be directed to make any refunds.

FERC Show Cause Orders

The FERC initiated a market manipulation investigation, partially in response to the bankruptcy filing of the Enron Corporation ("Enron") and to allegations that Enron may have engaged in manipulation of portions of the Western wholesale power market. In connection with that investigation, all sellers into Western electric and gas markets were required to submit data regarding short-term transactions in 2000-2001. In March 2003, the FERC staff issued its final report, which addressed various types of conduct that the FERC staff believed may have violated market monitoring protocols in the Cal ISO and Cal PX tariffs. Based on the final report, the FERC issued orders to certain companies, including Enron, requiring them to show cause why the FERC should not revoke their authorizations to sell electricity at market-based rates. In addition, the FERC staff recommended that the FERC issue orders requiring certain entities to show cause why they should not be required to disgorge profits associated with conduct deemed to violate the Cal ISO and Cal PX tariffs, or be subject to other remedial action.

In June 2003, the FERC issued two separate orders to show cause against PNM and over sixty other companies. In the first order (the "Gaming Practices Order"), the FERC asserted that certain entities, including PNM, appeared to have participated in activities that constitute gaming and/or anomalous market behavior in violation of the Cal ISO and Cal PX tariffs during the period January 1, 2000 to June 20, 2001. Specifically, PNM is alleged to have engaged in a practice termed "False Import," which FERC defined as the practice of exporting power generated by California and then reimported into California in order to avoid price caps on in-California generation. These allegations are based primarily on an initial Cal ISO report and the additional evidentiary submission by California parties. The Cal ISO was ordered to submit additional information on which the entities subject to the Show Cause Order should respond. For PNM, the potential disgorgement for alleged "False Import" transactions covers the period May 1, 2000 to October 1, 2000. After review of the additional Cal ISO data and consultation with

PNM, the FERC trial staff filed a motion to dismiss PNM from the case in August 2003. In September 2003, the California parties filed their objection to the dismissal of PNM from the case. In January 2004, the FERC issued an order granting trial staff's motion to dismiss PNM from the Gaming Partnerships docket on grounds that FERC staff's investigation did not reveal that PNM engaged in the practice of "False Import." As a result, the Company has been dismissed from the Gaming Practices proceedings.

In the second order to show cause (the "Gaming Partnerships Order"), the FERC asserts that certain entities, including PNM, acted in concert with Enron and other market participants to engage in activities that constitute gaming and/or anomalous market behavior in violation of the Cal ISO and Cal PX tariffs during the period January 1, 2000 to June 20, 2001. Specifically, PNM is alleged to have entered into "partnerships, alliances or other arrangements" with thirteen of its customers that allegedly may have been used as market manipulation schemes. The precise basis for certain of the FERC's allegations is not clear from the Gaming Partnerships Order, although it appears that most arise out of PNM's provision of "parking and lending" services to the identified companies. The potential remedies include disgorgement of unjust profits, as well as non-monetary remedies such as revocation of a seller's market-based rate authority.

In September 2003, PNM filed its responses to the Gaming Partnerships Order indicating that it did not engage in the alleged "partnerships, alliances or other arrangements" with the alleged parties. In October 2003, PNM filed testimony and exhibits in the case reasserting its response previously filed. The FERC ALJ has set the case for hearing on June 28, 2004. In January 2004, the FERC issued an order granting FERC staff's motion to dismiss seven of the thirteen PNM customers on grounds that there was no evidence to conclude that these companies used their commercial relationship with PNM to game the California ISO and PX markets. Of the six remaining PNM customers in the docket, the FERC staff has filed motions to dismiss or enter into settlement agreements with five of them. On February 27, 2004, the FERC staff and the California parties filed their testimony. The FERC staff did not identify any improper conduct by PNM. The California parties allege that PNM provided false information regarding parking transactions that allowed other parties to game the California market. They claim PNM should be required to disgorge unjust profits that they variously calculate as between approximately $6 million and $26 million in addition to non-monetary penalties. PNM believes that it has not engaged in improper conduct and intends to defend itself vigorously against these allegations. PNM continues to have discussions with the FERC Staff regarding possible dismissal of the charges against PNM.

Investigation of Anomalous Bidding Behavior and Practices in the Western Markets

In June 2003, the FERC issued an order finding that certain bids into the Cal ISO and Cal PX markets during the period May 1 through October 1, 2000 appear to have been excessive, in violation of the prohibitions against anomalous market behavior in the market monitoring protocols of the Cal ISO and Cal PX tariffs. The order directed the FERC's Office of Market Oversight and Investigation ("OMOI") to conduct a further investigation into bids in excess of $250 per MW during that period. In July 2003, PNM received a data request from OMOI to all sellers into the Cal ISO and Cal PX markets that submitted bids in excess of $250 per MW to the Cal ISO and Cal PX during the period covered by the investigation. In July 2003, PNM submitted its response to OMOI's data request, in which PNM provided justification of its bidding strategies during that period. In July 2003, PNM joined with other sellers in filing a request for rehearing of the June 2003 order, challenging the FERC's determination that bids above $250 per MW into the Cal ISO and Cal PX markets during the period May 1 through October 1, 2000 were prima facie excessive or in violation of the Cal ISO and Cal PX tariffs. PNM has received additional requests for information and data from OMOI, to which PNM responded. The investigation is currently pending and PNM cannot predict the outcome of OMOI's investigation, but intends to vigorously defend itself against any allegation of wrongdoing.

California Power Exchange and Pacific Gas and Electric Bankruptcies

In January and February 2001, Southern California Edison ("SCE") and PG&E, major purchasers of power from the Cal PX and Cal ISO, defaulted on payments due to Cal PX for power purchased from the Cal PX in 2000. These defaults caused the Cal PX to seek bankruptcy protection. PG&E subsequently also sought bankruptcy protection. PNM has filed its proofs of claims in the Cal PX and PG&E bankruptcy proceedings. Amounts due to PNM from the Cal PX or Cal ISO for power sold to them in 2000 and 2001 total approximately $7 million. The Company has provided allowances for the total amount due from the Cal PX and Cal ISO.

California Attorney General Complaint

In March 2002, the California Attorney General filed a complaint with the FERC against numerous sellers regarding prices for wholesale electric sales into the Cal ISO and Cal PX and to the California Department of Water Resources ("Cal DWR"). PNM was among the sellers identified in this complaint and filed its answer and motion to intervene. In its answer, PNM defended its pricing and challenged the theory of liability underlying the California Attorney General's complaint. In May 2002, the FERC entered an order denying the California Attorney General's request to initiate a refund proceeding, but directed sellers, including PNM, to comply with additional reporting requirements with regard to certain wholesale power transactions. PNM has made filings required by the May 2002 order. The California Attorney General filed a petition for review in the United States Court of Appeals for the Ninth Circuit. PNM intervened in the Ninth Circuit appeal and is participating as a party in that proceeding. The Ninth Circuit held oral arguments in the case in October 2003. The Company cannot predict the outcome of this appeal. As addressed below, the California Attorney General has also threatened litigation against PNM in state court in California based on similar allegations.

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California Attorney General Threatened Litigation

The California Attorney General has filed several lawsuits in California state court against certain power marketers for alleged unfair trade practices involving overcharges for electricity. In April 2002, the California Attorney General notified PNM of his intention to file a complaint in California state court against PNM concerning PNM's alleged failure to file rates for wholesale electricity sold in California and for allegedly charging unjust and unreasonable rates in the California markets. The letter invited PNM to contact the California Attorney General's office before the complaint was filed, and PNM has met several times with representatives of the California Attorney General's office. Further discussions are contemplated. To date, a lawsuit has not been filed by the California Attorney General and the Company cannot predict the outcome of this matter.

California Antitrust Litigation

Several class action lawsuits have been filed in California state courts against electric generators and marketers, alleging that the defendants violated the law by manipulating the market to grossly inflate electricity prices. Named defendants in these lawsuits include Duke Energy Corporation ("Duke") and related entities along with other named sellers into the California market and numerous other "unidentified defendants." Certain of these lawsuits were consolidated for hearing in state court in San Diego, California. In May 2002, the Duke defendants served a cross-claim on PNM. Duke also cross-claimed against many of the other sellers into California. Duke asked for declaratory relief and for indemnification for any damages that might ultimately be imposed on Duke. Several defendants removed the case to federal court in California. The federal judge has entered an order remanding the matter to state court, but the effect of that ruling has been stayed pending appeal. PNM has joined with other cross-defendants in motions to dismiss the cross-claim. The Company believes it has meritorious defenses but cannot predict the outcome of this matter.

Block Forward Agreement Litigation

In February 2002, PNM was served with a declaratory relief complaint filed by the State of California in California state court. The state's declaratory relief complaint seeks a determination that the state is not liable for its commandeering of certain energy contracts known as "Block Forward Agreements". The Block Forward Agreements were a form of futures contracts for the purchase of electricity at below-market prices and served as security for payment by PG&E and SCE for their electricity purchases through the Cal PX. When PG&E and SCE defaulted on payment obligations incurred through the Cal PX, the Cal PX moved to liquidate the Block Forward Agreements to satisfy in part the obligations owed by PG&E and SCE. Before the Cal PX could liquidate the Block Forward Agreements, California commandeered them for its own purposes. In March 2001, PNM and other similarly situated sellers of electricity through the Cal PX filed claims for damages with the California state Victims Compensation and Government Claims Board ("Victims Claims Board") on the theory that the state, by commandeering the Block Forward Agreements, had deprived them of security to which they were entitled under the terms of the Cal PX's tariff. The Victims Claims Board denied PNM 's claim in March 2002. PNM filed a complaint against the State of California in California state court in September 2002, seeking damages for the state's commandeering of the Block Forward Agreements and requesting judicial coordination with the state's declaratory relief action filed in February 2002 on the basis that the two actions raise essentially the same issues. The judge delayed establishing a procedural schedule for the case pending a determination of the Cal PX's status in the litigation. The judge has since held that the Cal PX could represent the interests of Cal PX participants in the litigation. The judge declined to set a procedural schedule because of his impending retirement. A new judge has now been appointed.

New Source Review Rules

In November 1999, the United States Department of Justice ("DOJ"), at the request of the Environmental Protection Agency ("EPA"), filed complaints against seven companies, alleging that the companies over the past 25 years had made modifications to their plants in violation of the New Source Review ("NSR") requirements and in some cases the New Source Performance Standard ("NSPS") regulations, which could result in the requirement to make costly environmental additions to older power plants. Whether or not the EPA will ultimately prevail is uncertain at this time. The EPA has reached settlements with several of the companies sued by the DOJ. In August 2003, in one of the pending enforcement cases against Ohio Edison Company, a federal district judge in Ohio ruled in favor of the EPA and against Ohio Edison. The judge accepted the legal theories advanced by the government and in particular found that eleven construction projects undertaken by the utility in that case between 1984 and 1998 were "modifications" of the plants within the meaning of the Clean Air Act, not "routine maintenance, repair or replacement" ("RMRR"). That case now proceeds to a remedy phase. By contrast, in a separate federal district court proceeding against Duke Energy Company, the court has made certain rulings in summary judgment motions that appeared to potentially validate elements of the industry position. If the EPA prevails in the position advanced in the pending litigation, PNM may be required to make significant capital expenditures, which could have a material adverse effect on the Company's financial position and results of operations.

No complaint has been filed against PNM by the EPA, and the Company believes that all of the routine maintenance, repair, and replacement work undertaken at its power plants was and continues to be in accordance with the requirements of NSR and NSPS. However, in October 2000, the New Mexico Environmental Department ("NMED") made an information request of PNM, advising PNM that the NMED was in the process of assisting the EPA in the EPA's nationwide effort "of verifying that changes made at the country's utilities have not inadvertently triggered a modification under

the Clean Air Act's Prevention of Significant Deterioration ("PSD") policies." PNM has responded to the NMED information request. In late June 2002, PNM received another information request from the NMED for a list of capital projects budgeted or completed in 2001 or 2002. PNM has responded to the additional NMED information request.

The National Energy Policy Development Group released the National Energy Policy in May 2001 which called for a review of the pending EPA enforcement actions. As a result of that review, in June 2002, the EPA announced its intention to pursue steps to increase energy efficiency, encourage emissions reductions and make improvements and reforms to the NSR program. The EPA announced that, among other things, the NSR program had impeded or resulted in the cancellation of projects that would maintain or improve reliability, efficiency and safety of existing power plants. The EPA's June 2002 announcement contemplated further rulemakings on NSR-related issues and expressly cautioned that the announcement was not intended to affect pending NSR enforcement actions. Thereafter, in December 2002, the EPA promulgated certain long-awaited revisions to the NSR rules, along with proposals to revise the RMRR exclusion contained in the regulations. In August 2003, the EPA issued its rule regarding RMRR. The new RMRR rule clarifies what constitutes RMRR of damaged or worn equipment, subject to safeguards to assure consistency with the Clean Air Act. It provides that replacements of equipment are routine only if the new equipment is (i) identical or functionally equivalent to the equipment being replaced; (ii) does not cost more than 20% of the replacement value of the unit of which the equipment is a part; (iii) does not change the basic design parameters of the unit; and (iv) does not cause the unit to exceed any of its permitted emissions limits. Legal challenges to the RMRR rule have been filed by several states; other states have intervened in support of the rule. How such challenges will ultimately be resolved cannot be predicted but an appellate court order has stayed the effect of the RMRR rule pending the outcome of the litigation.

Citizen Suit Under the Clean Air Act

Following required notification, the Grand Canyon Trust and the Sierra Club (collectively "GCT") filed a so-called "citizen suit" in federal district court in New Mexico against PNM (but not against the other SJGS co-owners) in May 2002. The suit alleged two violations of the Clean Air Act and related regulations and permits. First, GCT argued that the plant has violated, and is currently in violation of, the federal Prevention of Significant Deterioration ("PSD") rules, as well as the corresponding provisions of the New Mexico Administrative Code, at SJGS Units 3 and 4. Second, GCT alleged that the plant has "regularly violated" the 20% opacity limit contained in SJGS's operating permit and set forth in federal and state regulations at Units 1, 3 and 4. The lawsuit seeks penalties as well as injunctive and declaratory relief. PNM denied the material allegations in the complaint.

Both sides in the litigation filed motions for partial summary judgment and the court entered an order granting PNM's motion for summary judgment on the PSD issues, dismissing that portion of the case against PNM. A trial on certain preliminary liability issues on the opacity claims was held in November 2003. At this trial, the plaintiffs presented their case and PNM presented certain defenses, including that the measurement methods relied on by GCT are contradicted by other measurement methods or by other qualified scientific data. On February 2, 2004 the court entered a Memorandum Opinion on PNM's general defenses. The Memorandum Opinion rejected PNM's arguments concerning the proper method for determining opacity compliance, but allowed PNM to present evidence in the next part of the liability trial addressing and defending against liability for specific alleged opacity violations. A status conference was held on March 5, 2004. The court advised that the next phase of the liability trial would likely be scheduled in August or September 2004. A trial on remedy issues, if necessary, would be scheduled at a later date. PNM was directed to make a written settlement offer by April 1, 2004 with the plaintiffs directed to respond by April 16, 2004. The Company believes that it has meritorious defenses and continues to vigorously dispute the allegations. PNM's corporate policy continues to be to adhere to high environmental standards as evidenced by its ISO 14001 certification. The Company is, however, unable to predict the ultimate outcome of the matter.

Archeological Site Disturbance

The Company hired a contractor, Great Southwestern Construction, Inc. ("Great Southwestern"), to conduct certain "climb and tighten" activities on a number of electric transmission lines in New Mexico between July 2001 and December 2001. Those lines traverse a combination of federal, state, tribal and private properties in New Mexico. In late May 2002, the U.S. Forest Service ("USFS") notified PNM that apparent disturbances to archeological sites had been discovered in and around the rights-of-way for PNM's transmission lines in the Carson National Forest in New Mexico. Great Southwestern had performed "climb and tighten" activities on those transmission lines.

PNM has confirmed the existence of the disturbances, as well as disturbances associated with certain arroyos that may raise issues under section 404 of the Clean Water Act. PNM has given the Corps of Engineers notice concerning the disturbances in arroyos. The Corps of Engineers has acknowledged the Company's notice and asked PNM to cooperate in addressing these disturbances. The USFS verbally instructed PNM to undertake an assessment and possible related mitigation measures with respect to the archeological sites in question. PNM contracted for an archeological assessment and a proposed remediation plan with respect to the disturbances and has provided the assessment to the USFS and the federal Bureau of Land Management ("BLM"). The Santa Fe Forest issued a notice of non-compliance to PNM for alleged non-compliance with the terms and conditions of PNM's special use authorization relating to maintenance of PNM's power lines on USFS land.

A subsequent preliminary investigation into other transmission lines that were covered by the "climb and tighten" project indicated that there are disturbances on lands governed by other federal agencies and Indian tribes. PNM and Great Southwestern have provided notice of the potential disturbances to these other agencies and tribes. The Company had been informed that the USFS and BLM had commenced a criminal investigation

into Great Southwestern's activities on this project. However, the Company received verbal confirmation that the USFS and the BLM have decided to decline criminal prosecution under the Archeological Resources Protection Act ("ARPA") against PNM and Great Southwestern. The State of New Mexico requested information from PNM concerning the location of potential disturbances on state lands. The Navajo Nation has also requested further information concerning disturbances on Navajo land, but has provided written declination of criminal charges under ARPA against PNM and Great Southwestern. The Navajo Nation has indicated that it may pursue civil damages under ARPA. PNM and Great Southwestern are seeking the consent of BLM and the USFS to address impacted drainages under these agencies jurisdiction. PNM has provided Great Southwestern with notice and a demand for indemnity. Zurich Insurance, the insurer for Great Southwestern, has denied coverage and indemnity to PNM for this claim but has agreed to share the cost of a portion of the investigation of this claim. The Company is unable to predict the outcome of this matter and cannot estimate with any certainty the potential impact on the Company's operations.

Excess Emissions Reports

As required by law, whenever there are excess emissions from SJGS, due to such causes as start-up, shutdown, upset, breakdown or certain other conditions, PNM makes filings with the NMED. For some three years, PNM has been in discussions with NMED concerning excess emissions reports for the period after January 1997. During this period, NMED investigated the circumstances of these excess emissions and whether these emissions involve any violation of applicable permits and regulations. PNM and NMED have entered into several agreements tolling the running of the statute of limitations in order to allow NMED to complete its review of these filings. The present tolling agreement expires July 1, 2004. By letter dated September 12, 2003, the NMED advised PNM that NMED would not excuse certain of the emissions exceeding the operation permit emission permits. The NMED also stated that PNM had violated the opacity limits in the operating permit and articulated a construction of the standards that NMED would apply in evaluating opacity exceedances. Attached to the September 12, 2003 letter was what was identified as a "draft" compliance order assessing unspecified civil penalties. The NMED invited PNM to enter into discussions concerning the contents of the letter and of the draft compliance order and PNM and NMED have entered into such discussions. The compliance order has not yet been finalized and no proceeding against PNM has yet been commenced by NMED. PNM disagrees with the construction of its operating permit that is contained in the September 12, 2003 letter which represents a construction of the operating permit never previously advanced by NMED. PNM is unable to predict the outcome of this matter and cannot estimate the potential impact on the Company's operations.

Santa Fe Generating Station

PNM and the NMED conducted investigations of the gasoline and chlorinated solvent groundwater contamination detected beneath PNM's former Santa Fe Generating Station ("Santa Fe Station") site to determine the source of the contamination pursuant to a 1992 Settlement Agreement ("Settlement Agreement") between PNM and the NMED. The Settlement Agreement has been amended on several occasions to modify the scope of the investigation and remediation activities. No source of gasoline contamination in the groundwater was identified as originating from the site.

PNM is of the opinion that the data compiled indicates observed groundwater contamination originated from off-site sources. However, in August 2003, PNM elected to enter into a fifth amendment ("Fifth Amendment") to the Settlement Agreement with the NMED to avoid a prolonged legal dispute whereby PNM agreed to install additional remediation facilities consisting of an additional extraction well and two additional monitoring wells to address remaining gasoline contamination in the groundwater at and in the vicinity of the site. PNM will continue to operate the remediation facilities until the groundwater is cleaned up to applicable federal standards or until such time as the NMED determines that additional remediation is not required, whichever is earlier. The City of Santa Fe, the NMED and PNM entered into an amended Memorandum of Understanding relating to the continued operation of the Santa Fe Well and the remediation facilities called for under the latest Amended Settlement Agreement.

The Fifth Amendment notes the continued presence of chlorinated solvents in the groundwater under the former Santa Fe Generating Station and provides that once the remediation standards are met, the NMED anticipates that it will not require PNM to undertake any further investigation or remediation with respect to chlorinated solvents. In the event that chlorinated solvent concentrations remain at levels requiring further action, the NMED will not require PNM to take any further action with respect to the chlorinated solvent contamination until the NMED has reviewed any new data relating to the chlorinated solvent contamination and undertaken a good faith investigation into other potential sources. The NMED has acknowledged that at least a portion of the chlorinated solvent contamination observed beneath the Santa Fe Generating Station site has originated from off-site sources. In September 2003, PNM was verbally informed that the Superfund Oversight Section of the NMED is conducting an investigation into the chlorinated solvent contamination at the former Santa Fe Generating Station site, including other possible sources for the chlorinated solvents in the groundwater. The NMED states that it expects to have the results of its investigation complete by September of 2004.

Natural Gas Royalties Qui Tam Litigation

In 1999, a complaint was served on the Company alleging violations of the False Claims Act by PNM and its subsidiaries, Gathering Company and Processing Company (collectively, the "Company" for purposes of this discussion), by purportedly failing to properly measure natural gas from Federal and tribal properties in New Mexico, and consequently, underpaying royalties owed to the Federal government. A private relator is pursuing the lawsuit. The complaint was served after the United States Department of Justice declined to intervene to pursue the lawsuit. The complaint seeks actual damages, treble damages, costs and attorneys fees, among other relief.

Currently the parties are engaged in discovery on the issue of whether the relator meets the requirements for bringing a claim under the False Claims Act. The Company expects to participate with other defendants in a motion to dismiss on the ground that the relator does not meet those requirements.

The Company is vigorously defending this lawsuit and is unable to estimate the potential liability, if any, or to predict the ultimate outcome of this lawsuit.

Dugan Production Corporation Litigation

In July 2002, Dugan Production Corp. filed a lawsuit in the County of San Juan, New Mexico, against the SJCC. In September 2002, the SJCC removed the lawsuit to the United States District Court for the District of New Mexico. The lawsuit seeks to enjoin the underground mining of coal from a portion of the land that is to be used for the underground mine. The plaintiff also seeks monetary damages.

The SJCC, through leases with the federal government and the State of New Mexico, owns coal interests with respect to the underground mine. The plaintiff, through leases with the federal government, the State of New Mexico and certain private parties, claims to own certain oil and gas interests in portions of the land that is to be used for the underground mine. The plaintiff alleges that the SJCC's underground coal mining operations have or will interfere with plaintiff's gas production and result in the dissipation of natural gas that it otherwise would be entitled to recover. The plaintiff also alleges, and seeks a declaration by the court, that the rights under its leases are senior and superior to the rights of the SJCC.

The SJCC has informed the Company that SJCC intends to vigorously dispute the litigation. In September 2002, the SJCC filed a motion to dismiss the claims against it on several grounds. Discovery for the lawsuit has not yet started. The Company cannot predict the ultimate outcome of the litigation or whether the litigation will adversely affect the amount of coal available, or its price for SJGS.

Richardson Matter

Another gas leaseholder, Richardson Operating Company ("Richardson"), has leases in the area of the San Juan Mine and has asserted claims against SJCC. The Company understands that discussions with Richardson are ongoing, although no formal litigation has been filed.

Asbestos Cases

The Company was named in 2003 as one of a number of defendants in 21 personal injury lawsuits relating to alleged exposure to asbestos. All of these cases involve claims of individuals, or their descendents, who worked for contractors building, or working at, Company power plants. Some of the claims relate to construction activities during the 1950's and 1960's, while other claims generally allege exposure during the last 30 years. The Company has never manufactured, sold or distributed products containing asbestos. All of these cases involve multiple defendants. The state district judge in six of these cases recently entered a stay of all proceedings due to the bankruptcy of one of defendants; however, the plaintiffs in these cases have moved to modify the stay so that the cases can proceed against the remaining defendants. The Company was insured by a number of different insurance policies during the time period at issue in these cases. The Company intends to vigorously defend against these lawsuits. Although the Company is unable to fully predict the outcome of this litigation, the Company believes that it has adequate reserves and insurance coverage such that the outcome of these legal proceedings would not have a material impact on the financial condition of the Company.

San Angelo Electric Service Company ("SESCO") Matter

In October 2003, the Texas Commission on Environmental Quality ("TCEQ") requested information from PNM concerning any involvement that PNM had with the SESCO of San Angelo, Texas. PNM is informed that the TCEQ is conducting a site investigation of a SESCO facility in San Angelo, Texas pursuant to the Texas Solid Waste Act and that the SESCO site has been referred to the Superfund Site Discovery and Assessment Program. The primary concern appears to be polychlorinated biphenals ("PCBs"). The TCEQ is conducting the site investigation to determine what remediation activities are required at the SESCO site and to identify potentially responsible parties ("PRPs"). In January 2004, PNM submitted its preliminary response to the TCEQ request for information. The response states that PNM previously had a "requirements" contract with SESCO for the repair of electric transformers. It appears that a number of transformers were sent to SESCO for repair. In addition, it appears that PNM sold a number of retired transformers to SESCO. PNM has not received a response from the TCEQ concerning the information provided in PNM's response. PNM has not been named as a PRP for the SESCO site. PNM is unable to predict the outcome of this matter.

Other

There are various claims and lawsuits pending against the Company. The Company is also subject to federal, state and local environmental laws and regulations, and is currently participating in the investigation and remediation of numerous sites. In addition, the Company periodically enters into financial commitments in connection with its business operations. It is not possible at this time for the Company to determine fully the effect of all litigation on its consolidated financial statements. However, the Company has recorded a liability where the litigation effects can be estimated and where an outcome is considered probable. The Company does not expect that any known lawsuits, environmental costs and commitments will have a material adverse effect on its financial condition or results of operations.

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The Company is involved in various legal proceedings in the normal course of its business. The associated legal costs for these legal matters are accrued when incurred. It is also the Company's policy to accrue for legal costs expected to be incurred in connection with Statement of Financial Accounting Standards No. 5 "Accounting for Contingencies" ("SFAS 5") legal matters when it is probable that a SFAS 5 liability has been incurred and the amount of expected legal costs to be incurred is reasonably estimable. These estimates include costs for external counsel professional fees.

Risks and Uncertainties

The Company's future results may be affected by various factors outside of its control, including: changes in regional economic conditions; the outcome of labor negotiations with unionized employees; fluctuations in fuel, purchased power and gas prices; the actions of utility regulatory commissions; changes in law and environmental regulations; the success of its planned generation expansion; the cost and outcome of litigation and other legal proceedings and investigations; the performance of generation facilities; changes in accounting rules and standards; and external factors such as weather and water supply. Because of pending federal regulatory reforms, the public utility industry is undergoing a fundamental change. New Mexico has repealed the Electric Utility Industry Restructuring Act of 1999 and therefore has abandoned its plans to transform the industry from one of vertically-integrated monopolies to one with deregulated, competitive generation. However, the FERC has proposed a "Standard Market Design" ("SMD") to establish rules for a market-based approach for wholesale transactions over the transmission grid. The FERC's efforts have been opposed by a number of states, primarily in the West and in the Southeast, because of concern that the SMD does not adequately take into account regional differences. Moreover, Congress is currently debating energy legislation which could affect the FERC's activities. In an attempt to ease concerns, on April 28, 2003, the FERC issued a White Paper on "Wholesale Power Market Platform" describing changes it intended to make to its SMD proposed rules. The Company's future results will be impacted by the form of the FERC rules, if adopted; the costs of complying with rules and legislation that may call for regulatory reforms for the industry; and the resulting market prices for electricity and natural gas. In addition, the Company has in place a retail electric rate freeze through 2007 so that the Company's financial results will depend on its ability to control costs and grow revenues, and the implications of uncontrollable factors such as weather, water supply, litigation and economic conditions.

(14) ENVIRONMENTAL ISSUES

The normal course of operations of the Company necessarily involves activities and substances that expose the Company to potential liabilities under laws and regulations protecting the environment. Liabilities under these laws and regulations can be material and in some instances may be imposed without regard to fault, or may be imposed for past acts, even though the past acts may have been lawful at the time they occurred. Sources of potential environmental liabilities include the Federal Comprehensive Environmental Response Compensation and Liability Act of 1980 and other similar statutes.

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

The Company's recorded minimum liability estimated to remediate its identified sites was $6.8 million and $8.5 million as of December 31, 2003 and 2002, respectively. The ultimate cost to clean up the Company'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; and the time periods over which site remediation is expected to occur.

For the year ended December 31, 2003, 2002 and 2001, the Company spent $3.2 million, $0.7 million and $1.7 million, respectively, for remediation. The majority of the December 31, 2003 environmental liability is expected to be paid over the next five years, funded by cash generated from operations. Future environmental obligations are not expected to have a material impact on the results of operations or financial condition of the Company.

(15) COMPANY REALIGNMENT

On August 22, 2002, the Company was realigned due to the changes in the electric industry and particularly, the negative impact on the Company's earnings and growth prospects from wholesale market uncertainty. The changes included consolidation of similar functions. A total of 85 salaried and hourly employees were notified of their termination as part of the realignment. In accordance with EITF 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity", the Company incurred a liability of $8.8 million for severance and other related costs associated with the involuntary termination of employees, which was charged to operations in the quarter ended September 30, 2002 and is included in administrative and general in the consolidated statements of earnings for the year ended December 31, 2002. The Company paid $8.6 million through December 31, 2003.

(16) OTHER INCOME AND DEDUCTIONS

The following table details the components of other income and deductions for PNM Resources, Inc. and subsidiaries (In thousands):

	YEAR ENDED DECEMBER 31,		
	2003	2002	2001
Other income:			
Investment income	$ 41,826	$ 44,954	$ 48,742
AFUDC	2,589	–	–
Gross receipts tax credits	2,893	–	–
Miscellaneous non-operating income	5,397	3,406	3,405
	$ 52,705	$ 48,360	$ 52,147
Other deductions			
Loss on reacquired debt write off	$ 16,576	$ –	$ –
Transition costs write off	16,720	–	–
Merger costs and related legal costs	–	(2,436)	17,975
Write-off of Avistar investments	–	–	13,089
Nonrecoverable coal mine decommissioning costs	–	–	12,979
Write-off of regulatory assets	–	–	11,100
Contribution to PNM Foundation	–	–	5,000
Transmission line project write-off	–	4,818	–
Miscellaneous non-operating deductions	12,857	9,924	7,114
	$ 46,153	$ 12,306	$ 67,257

(17) PRO-FORMA EFFECT OF CHANGES IN ACCOUNTING PRINCIPLES

The following table, presented for comparative purposes, shows the pro-forma effect assuming the adoption of SFAS 143 and the change in measurement date of the pension and other post-retirement benefit plans applied retroactively to the Company's earnings. (In thousands)

	YEAR ENDED DECEMBER 31,	
	2002	2001
Net Earnings as previously reported	$ 63,686	$ 149,847
Change of Pension Measurement Date, net of tax expense (benefit) of $(167) and $144 (note 9)	(255)	219
Adoption of Asset Retirement Obligations, net of tax benefit of $3,048 and $3,088 (note 12)	4,651	4,712
Net Earnings Available to Common Stock	$ 68,082	$ 154,778
Earnings per Share:		
Net Earnings as previously reported	$ 1.63	$ 3.83
Change of Pension Measurement Date (note 9)	(0.01)	(0.01)
Adoption of Asset Retirement Obligations, net of tax of $0.08 and $0.08 (note 12)	0.12	0.12
Net Earnings Available to Common Stock	$ 1.74	$ 3.94
Diluted Earnings Per Share as previously reported	$ 1.61	$ 3.77
Diluted Earnings Per Share net of tax of $0.08 and $0.07	$ 1.73	$ 3.88

(18) NEW AND PROPOSED ACCOUNTING STANDARDS

Financial Accounting Standards Board Interpretation No. 46, "Consolidation of Variable Interest Entities", an interpretation of Accounting Research Bulletin No. 51, "Consolidated Financial Statements" (revised December 2003) ("FIN 46R"). In January 2003, the Financial Accounting Standards Board ("FASB") issued FIN 46 to address the consolidation of variable interest entities ("VIEs"). FIN 46 applied immediately to VIEs created after January 31, 2003, and to VIEs in which an enterprise obtains an interest after that date. It applied in the first fiscal year or interim period beginning after June 15, 2003, to VIEs in which an enterprise holds a variable interest that it acquired before February 1, 2003. Upon adoption of FIN 46, the Company did not identify any VIEs for which it is the primary beneficiary or has significant involvement. In December 2003, the FASB issued FIN 46R to clarify provisions of FIN 46 and exempt certain entities from its requirements. The Company must apply the provisions of FIN 46R for special purpose entities (SPEs) created prior to February 1, 2003, at the end of the annual reporting period ending after December 15, 2003. The Company

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evaluated all its interests in entities that may be deemed SPEs under the provisions of FIN 46R and concluded that no additional entities need to be consolidated. The Company is required to adopt FIN 46R for non-SPEs at the end of the first interim reporting period ending after March 15, 2004. The Company is currently evaluating the impact of adopting FIN 46R applicable to non-SPEs created prior to February 1, 2003 and is unable to predict its impact on the Company's operating results and financial position at this time.

Statement of Financial Accounting Standards No. 132 (revised 2003) "Employers' Disclosures about Pensions and Other Postretirement Benefits" ("SFAS 132(R)"). This statement was issued in December of 2003 and replaces FASB statement No. 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits" ("SFAS 132"). SFAS 132(R) addresses disclosure only and does not change the measurement and recognition provisions of FASB Statement No. 87, "Employers' Accounting for Pensions", Statement No. 88, "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits", and Statement No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions". Additional disclosures to be included in the annual report include additional information regarding plan assets, the accumulated benefit obligations (for defined benefit pension plans), projected benefit payments, estimated expected contributions, assumptions used in the calculations and the measurement date of the plan (see Note 9 – Pension and Other Post-retirement Benefits for additional disclosures). Disclosures to be included in interim reports include the amount of net periodic benefit cost recognized (showing the components separately) and contributions paid and expected to be paid during the current fiscal year, if significantly different from amounts previously disclosed. This statement is effective for fiscal years ending after December 15, 2003 and interim periods beginning after December 15, 2003. The disclosure regarding estimated future benefit payments shall be effective for fiscal years ending after June 15, 2004.

EITF 01-8 "Determining Whether an Arrangement Contains a Lease." EITF 01-8 provides guidance on how to determine whether an arrangement contains a lease that is within the scope of Statement of Financial Accounting Standards No. 13, "Accounting for Leases" ("SFAS 13"). The guidance is based on whether the arrangement conveys to the purchaser (lessee) the right to use a specific asset. A consensus was reached on the accounting for substantial services provided by the lessor in these arrangements in which these services are not executory costs as the term is used in SFAS 13. The guidance provides as to when an arrangement should be reassessed to determine whether it contains a lease and how to account for these subsequent changes in lease classification. EITF 01-8 must be applied to arrangements agreed to, committed to, modified, or acquired in business combinations initiated after April 1, 2003. Upon adoption, EITF 01-8 did not have a material impact on the Company's financial condition or results of operation.

EITF 02-9 "Accounting for Changes That Result in a Transferor Regaining Control of Financial Assets Sold." EITF 02-9 addresses how to apply the accounting requirements of paragraph 55 of Statement of Financial Accounting Standards No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities" ("SFAS 140"), with respect to beneficial interests held by the transferor and loans that do not meet the definition of a security, including whether the transferor should recognize a gain or loss when the provisions of paragraph 55 are applied. Paragraph 55 of SFAS No. 140 requires a transferor to recognize in its financial statements assets previously accounted for appropriately as having been sold when one or more of the conditions regarding control of the assets are no longer met. EITF 02-9 must be applied to events occurring after April 2, 2003. Upon adoption, EITF 02-9 did not have a material impact on the Company's financial condition or results of operation.

FASB Staff Position No. 106-1 "Accounting and Disclosure Requirements Related to Medicare Prescription Drug, Improvement and Modernization Act of 2003 ("the Act")" ("FSP 106-1"). The Act introduces a prescription drug benefit under Medicare ("Medicare Part D") as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. FSP 106-1 permits a sponsor of a postretirement health care plan that provides a prescription drug benefit to make a one-time election to defer accounting for the effects of the Act. Authoritative guidance on accounting for the federal subsidy is pending and could require a change in previously reported information. Disclosures are required regardless of whether the sponsor elects deferral. FSP 106-1 is effective for fiscal years or interim periods ending after December 7, 2003 and interim periods beginning after December 15, 2003. Because of various uncertainties related to the Company's response to this litigation and the appropriate accounting methodology for this event, the Company has elected to defer financial recognition of this legislation until the FASB issues final accounting guidance. When issued, that final guidance could require the Company to change previously reported information. This deferral election is permitted under FSP 106-1.

QUARTERLY OPERATING RESULTS

Quarterly Operating Results

The unaudited operating results by quarters for 2003 and 2002 are as follows (In thousands, except per share amounts):

	QUARTER ENDED			
	MARCH 31	JUNE 30	SEPTEMBER 30	DECEMBER 31
2003:				
Operating Revenues	$ 387,691	$ 340,211	$ 385,161	$ 342,651
Operating Income	33,426	29,914	35,881	19,371
Net Earnings Before Cumulative Effect of Changes in Accounting Principles	10,748	17,596	16,568	13,640
Net Earnings	48,170(A)	17,596	16,568(B)	12,839
Net Earnings Per Share (Basic):				
Net Earnings Before Cumulative Effect of Changes in Accounting Principles	0.28	0.45	0.41	0.34
Net Earnings	1.23	0.45	0.41	0.32
Net Earnings Per Share (Diluted):				
Net Earnings Before Cumulative Effect of Changes in Accounting Principles	0.27	0.44	0.41	0.34
Net Earnings	1.22	0.44	0.41	0.32
2002:				
Operating Revenues	$ 301,817	$ 250,189	$ 274,675	$ 292,013
Operating Income	32,687	19,449	29,135	20,503
Net Earnings Before Cumulative Effect of Changes in Accounting Principles	24,803	11,010	17,650	10,223
Net Earnings	24,803	11,010	17,650(C)	10,223
Net Earnings Per Share (Basic):				
Net Earnings Before Cumulative Effect of Changes in Accounting Principles	0.63	0.28	0.45	0.26
Net Earnings	0.63	0.28	0.45	0.26
Net Earnings Per Share (Diluted):				
Net Earnings Before Cumulative Effect of Changes in Accounting Principles	0.63	0.28	0.45	0.26
Net Earnings	0.63	0.28	0.45	0.26

In the opinion of management of the Company, all adjustments (consisting of normal recurring accruals) necessary for a fair statement of the results of operations for such periods have been included.

(A) Effective January 1, 2003, the Company adopted SFAS 143, Accounting for Asset Retirement Obligations. The effect was reported as a cumulative effect of a change in accounting principle, which increased the Company's net earnings by approximately $37.4 million, net of tax expense of approximately $24.5 million, or $0.93 per diluted common share. In the first quarter of 2003, the Company wrote-off transition costs previously capitalized in anticipation of deregulation, which decreased the Company's net earnings by approximately $9.5 million, net of tax benefit of $7.2 million, or $0.24 per diluted common share.

(B) In the third quarter of 2003, the Company recognized a loss on reacquired debt, which decreased the Company's net earnings by $10.0 million, net of tax benefit of $6.6 million, or $0.25 per diluted common share.

(C) In the third quarter of 2002, the Company was realigned due to changes in the industry, which decreased the Company's net earnings by $5.3 million, net of tax benefit of $3.5 million, or $0.14 per diluted common share.

Independent Auditors' Report on Schedules

TO THE BOARD OF DIRECTORS AND STOCKHOLDERS OF PNM RESOURCES, INC. AND PUBLIC SERVICE COMPANY OF NEW MEXICO

We have audited the consolidated financial statements of PNM Resources, Inc. and subsidiaries and Public Service Company of New Mexico and subsidiaries (collectively, the "Companies") as of December 31, 2003 and 2002, and for each of the three years in the period ended December 31, 2003, and have issued our reports thereon dated March 8, 2004 (which reports express unqualified opinions and include explanatory paragraphs referring to the adoption of Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations, effective January 1, 2003 and the change in actuarial valuation measurement date for the pension plan and other post-retirement benefits from September 30 to December 31); such financial statements and reports are included in this Annual Report on Form 10-K of PNM Resources, Inc. and Public Service Company of New Mexico. Our audits also included the consolidated financial statement schedules listed in Item 15. These financial statement schedules are the responsibility of each of the respective Companies' management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly in all material respects the information set forth therein.

DELOITTE & TOUCHE LLP
Omaha, Nebraska
March 8, 2004

COMPARATIVE OPERATING STATISTICS

	2003	2002	2001	2000	1999
Utility Operations Sales:					
Energy Sales--KWh (in thousands):					
Residential	**2,405,488**	2,298,542	2,197,889	2,171,945	2,027,589
Commercial	**3,379,147**	3,254,576	3,213,208	3,133,996	2,981,656
Industrial	**1,346,940**	1,612,723	1,603,266	1,544,367	1,559,155
Other ultimate customers	**221,137**	240,665	240,934	238,635	235,183
TOTAL KWH SALES	**7,352,712**	7,406,506	7,255,297	7,088,943	6,803,583
Gas Throughput—Decatherms (in thousands):					
Residential	**27,416**	29,627	27,848	28,810	32,121
Commercial	**10,810**	12,009	10,421	9,859	11,106
Industrial	**485**	749	3,920	5,038	2,338
Other	**5,510**	4,807	4,355	6,426	6,538
TOTAL GAS SALES	**44,221**	47,192	46,544	50,133	52,103
Transportation throughput	**50,756**	44,889	51,395	44,871	40,161
TOTAL GAS THROUGHPUT	**94,977**	92,081	97,939	95,004	92,264
Revenues (in thousands):					
Electric Revenues:					
Residential	**$ 203,710**	$ 197,174	$ 187,600	$ 186,133	$ 184,088
Commercial	**252,876**	247,800	242,372	238,243	238,830
Industrial	**67,388**	82,009	82,752	79,671	85,828
Other ultimate customers	**14,069**	14,942	14,795	14,618	13,777
TOTAL REVENUES TO ULTIMATE CUSTOMERS	**538,043**	541,925	527,519	518,665	522,523
Transmission revenues	**19,453**	23,150	26,553	16,855	15,519
Miscellaneous electric revenues	**5,807**	5,014	5,154	3,163	2,826
TOTAL ELECTRIC REVENUES	**$ 563,303**	$ 570,089	$ 559,226	$ 538,683	$ 540,868
Gas Revenues:					
Residential	**$ 226,799**	$ 176,264	$ 221,409	$ 203,208	$ 160,311
Commercial	**72,269**	53,734	65,654	56,283	39,311
Industrial	**2,820**	2,872	27,519	24,206	8,560
Other	**37,473**	26,781	36,495	37,360	26,168
Revenues from gas sales	**339,361**	259,671	351,077	321,057	234,340
Transportation	**18,906**	17,735	20,188	14,163	12,390
TOTAL GAS REVENUES	**$ 358,267**	$ 277,406	$ 371,265	$ 335,220	$ 246,730
TOTAL UTILITY REVENUES	**$ 921,570**	$ 847,495	$ 930,491	$ 873,903	$ 787,598

COMPARATIVE OPERATING STATISTICS

	2003	2002	2001	2000	1999
Utility Customers at Year End:					
Electric:					
Residential	358,099	345,588	340,656	332,332	321,949
Commercial	42,391	41,092	40,065	39,525	38,435
Industrial	296	311	377	371	375
Other ultimate customers	822	796	924	625	625
TOTAL ULTIMATE CUSTOMERS	401,608	387,787	382,022	372,853	361,384
Sales for Resale	72	76	79	81	83
TOTAL CUSTOMERS	401,680	387,863	382,101	372,934	361,467
Gas:					
Residential	421,104	411,642	404,753	398,623	390,428
Commercial	34,645	35,194	32,894	32,626	32,116
Industrial	46	58	50	50	51
Other	2,983	3,664	3,528	3,612	3,688
Transportation	40	27	34	32	32
TOTAL CUSTOMERS	458,818	450,585	441,259	434,943	426,315
Wholesale Operations Sales:					
Energy Sales—MWh:					
Long-term contracts	2,719,432	844,168	1,463,031	330,003	1,185,916
Forward sales	3,237,525	-	-	-	-
Short-term sales	5,531,019	7,269,242	10,596,004	10,213,725	8,585,705
TOTAL SALES TO ULTIMATE CUSTOMERS	11,487,976	8,113,410	12,059,035	10,543,728	9,771,621
Revenues (in thousands):					
Long-term contracts	$ 147,447	$ 58,546	$ 77,250	$ 87,731	$ 66,353
Forward sales	151,543	3,575	(2,572)	(14,768)	(2,300)
Short-term sales	234,843	207,674	1,247,471	577,811	260,856
TOTAL WHOLESALE REVENUES	$ 533,833	$ 269,795	$ 1,322,149	$ 650,774	$ 324,909
Customers at Year End:					
Wholesale	72	76	79	81	83
Generation Statistics:					
Reliable Net Capability—KW	1,742,000	1,734,000	1,521,000	1,521,000	1,521,000
Coincidental Peak Demand—KW	1,861,000	1,456,000	1,397,000	1,368,000	1,291,000
Average Fuel Cost per Million BTU	$ 1.4120	$ 1.3910	$ 1.6007	$ 1.3827	$ 1.3169
BTU per KWh of Net Generation	10,854	10,568	10,549	10,547	10,490

SHAREHOLDER INFORMATION

2004 ANNUAL MEETING

The 2004 Annual Meeting of Stockholders will be held at 9:00 am on May 18, 2004 at The South Broadway Cultural Center, 1025 Broadway SE, Albuquerque, NM. Proxies will be requested from stockholders when the notice of meeting and proxy statement are mailed on or about April 7.

TRANSFER AGENT AND REGISTRAR

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Website: melloninvestor.com

Overnight, Registered or Certified Mail:
Mellon Investor Services
85 Challenger Road
Ridgefield Park, NJ 07660

DIVIDEND REINVESTMENT AND DIRECT STOCK PURCHASE PLAN

PNM Resources offers a dividend reinvestment and direct stock purchase plan as a service to both new investors and current shareholders. In addition to full or partial reinvestment of dividends, the PNM Direct Plan gives shareholders the opportunity to make direct cash investments. More information about the Plan and enrollment forms are available by calling Mellon Investor Services at 1-877-663-7775 or by visiting Mellon's website at melloninvestor.com.

Mellon has done an excellent job as our agent in processing requests for transfer of share ownership, address changes and other routine transactions. But if you prefer to deal with someone in PNM Shareholder Services, please feel free to call us anytime during business hours. You can reach a PNM representative either by calling the Mellon Investors toll-free line (1-877-663-7775) and pressing "#" to connect to PNM or by calling us directly at 1-800-545-4425.

SECURITIES INFORMATION

Exchange Listing and Stock Symbol

PNM Resources' common stock is listed on the New York Stock Exchange under the symbol PNM. The newspaper listing is PNM Res. As of March 15, 2004, there were 14,717 common shareholders of record.

COMMON STOCK PRICES* AND DIVIDENDS PAID: (IN DOLLARS)

	2003			2002		
QTR.	DIVIDEND	HIGH	LOW	DIVIDEND	HIGH	LOW
1	$0.22	$23.990	$18.950	$0.20	$30.760	$25.330
2	$0.23	$27.850	$21.850	$0.22	$30.550	$23.300
3	$0.23	$28.970	$25.370	$0.22	$24.330	$17.250
4	$0.23	$29.470	$26.290	$0.22	$24.670	$17.470

*As reported by New York Stock Exchange Composite Price History

For further information regarding dividends, please see discussion on pages 36 and 37.

REPORTS AND PUBLICATIONS

Copies of the Company's Form 10-K (annual report) and Form 10-Q (quarterly report) to the Securities and Exchange Commission (SEC), proxy statement, all news releases, an 11-year Financial and Statistical Report and other corporate literature are available free upon request by calling 505-241-2868, by accessing the information on the Internet at pnm.com or by writing the Vice President, Investor Relations.

For up-to-date stock quotes, quarterly earnings results and other important information, visit the PNM website at pnm.com.

CONTACT INFORMATION

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PNM Resources

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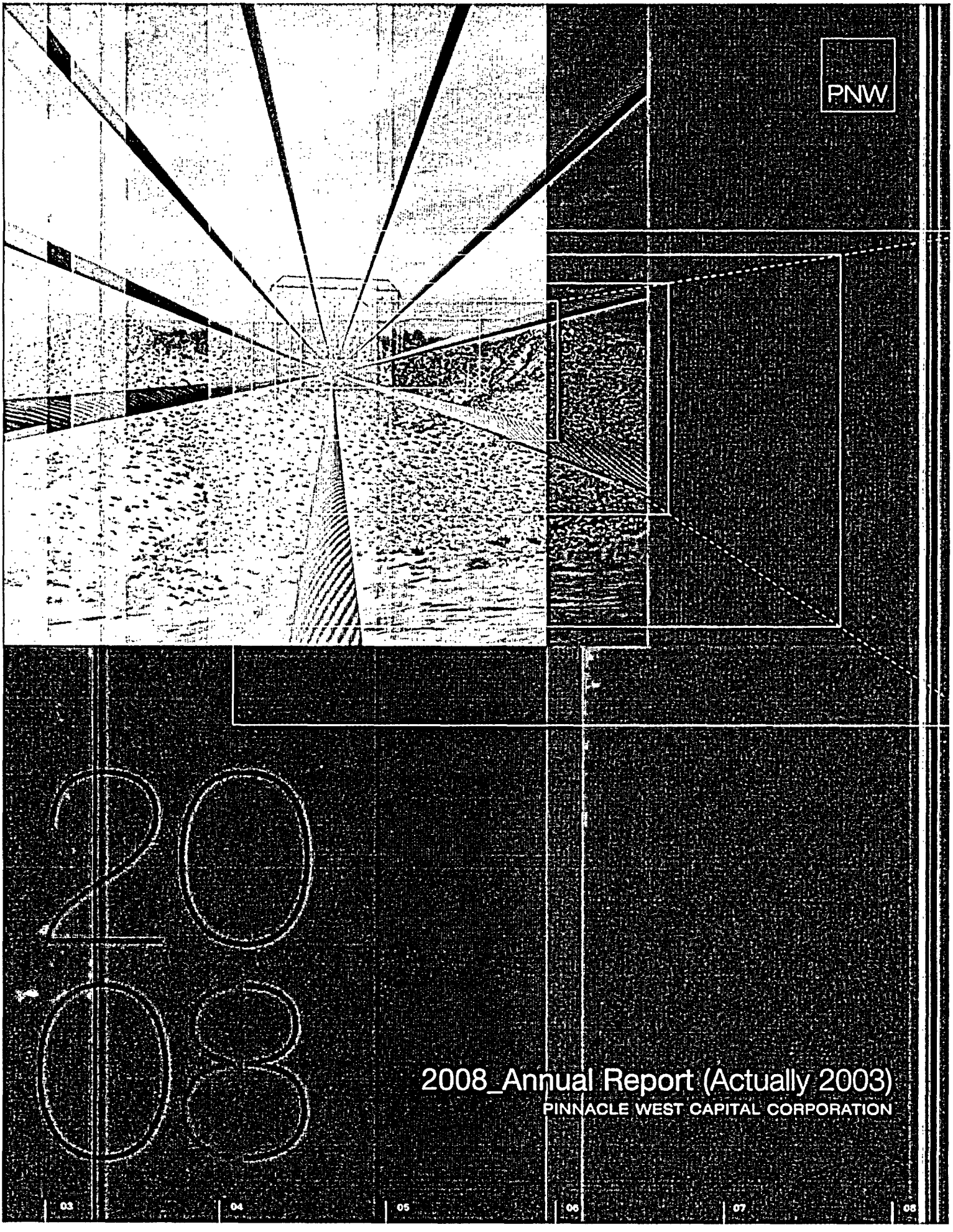


2008_Annual Report (Actually 2003)

PINNACLE WEST CAPITAL CORPORATION

ABOUT OUR COMPANY

Pinnacle West is a Phoenix-based company with consolidated assets of approximately $9.5 billion and consolidated revenues of $2.8 billion. Through our subsidiaries, we generate, sell and deliver electricity and sell energy-related products and services to retail and wholesale customers in the western United States. We also develop residential, commercial and industrial real estate products.

ABOUT THIS YEAR'S ANNUAL REPORT

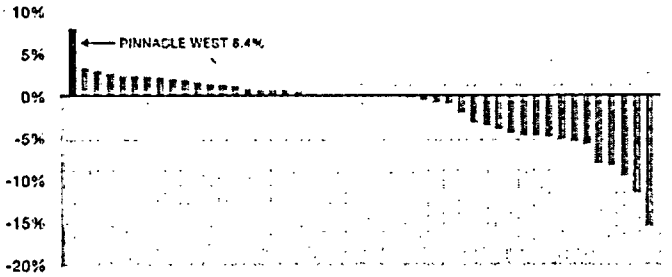
No, this is not actually our 2008 Annual Report. However, at Pinnacle West we take a long-term view, and the issues we will face five years from now are the issues we must address today. This is why we, and our Annual Report, are focused on the future – for shareholders, for customers and for Arizona.

TABLE OF CONTENTS

CORE STRATEGIC OBJECTIVES

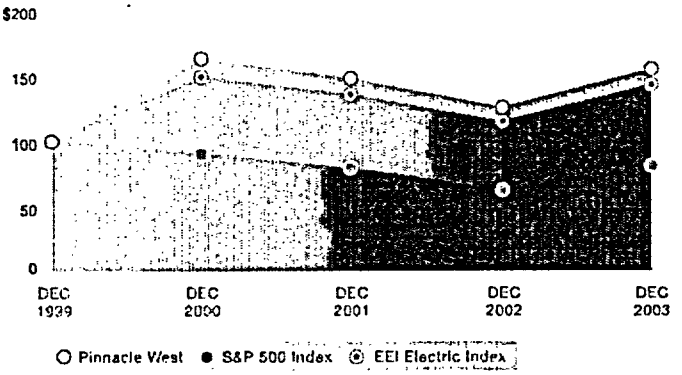
- Focus on superior long-term total returns for shareholders
- Provide Arizona electricity customers with reliable energy at stable prices
- Capture growth opportunities in our electricity markets
- Actively manage our costs and business risks
- Maximize the long-term value of our assets
- Maintain a disciplined focus on our long-term goals while remaining agile
- Increase our generation portfolio consistent with our native load, cash flow and market conditions

ELECTRIC UTILITIES AVERAGE ANNUAL DIVIDEND GROWTH 1994 TO 2003



PINNACLE WEST STOCK PERFORMANCE COMPARISON

Value of $100 invested on December 31, 1999, with dividends reinvested



FINANCIAL HIGHLIGHTS

(dollars in thousands, except per share amounts)

Year Ended December 31,	2003	2002	2001	Growth Rate 2003 vs 2002	Growth Rate 2002 vs 2001
INCOME HIGHLIGHTS					
Operating revenues	$ 2,817,852	$ 2,440,288	$ 2,634,768	15.5%	(7.4)%
Income from continuing operations	$ 230,576	$ 206,198	$ 327,367	11.8%	(37.0)%
Net income	$ 240,579	$ 149,408	$ 312,166	61.0%	(52.1)%
BALANCE SHEET HIGHLIGHTS					
Total assets – year-end	$ 9,536,378	$ 9,139,157	$ 8,529,124	4.3%	7.2 %
Common stock equity – year-end	$ 2,829,779	$ 2,686,153	$ 2,499,323	5.3%	7.5 %
PER SHARE HIGHLIGHTS					
Earnings per share from continuing operations – diluted	$ 2.52	$ 2.43	$ 3.85	3.7%	(36.9)%
Net income – diluted	$ 2.63	$ 1.76	$ 3.68	49.4%	(52.2)%
Indicated annual dividend – year-end	$ 1.80	$ 1.70	$ 1.60	5.9%	6.3 %
Book value per share – year-end	$ 30.97	$ 29.40	$ 29.46	5.3%	(0.2)%
STOCK PERFORMANCE					
Stock price per share – year-end	$ 40.02	$ 34.09	$ 41.85		
Stock price appreciation	17.4%	(18.5)%	(12.1)%		
Total return	23.1%	(14.8)%	(9.0)%		
Market capitalization – year-end	$ 3,653,343	$ 3,115,142	$ 3,549,924	17.3%	(12.2)%

To Our Shareholders

You read correctly, our cover says "2008 Annual Report." There's a good reason. This is where we spend a lot of our time – planning to meet the energy needs of customer demand that's growing 4 to 5 percent each year. For Pinnacle West, 2008 is here – now.

This emphasis on the future is more than a clever idea. It's a way to bring our vision into sharp focus for customers, investors and policymakers. A long-term view has always been critically important to us. Growth makes our future orientation even more crucial today. There is simply no room for error or delay – or extended regulatory uncertainty.

We are focused with laser-like intensity on the outcome of our current rate case and what it will say about the future – for our customers and our state.

Understanding how we got to this point – at the end of one state regulatory era but not yet firmly in a new era – requires a quick look at where we are now and how we got here.

HOW WE GOT TO NOW

In 2003, our year-end earnings were in line with expectations, and we strengthened our liquidity position. We had another strong year of operating performance. Our gas- and coal-fired power plants recorded some of their best production years ever. And the Palo Verde Nuclear Generating Station was the largest power producer of any kind in the U.S. for the 12th straight year.

We also achieved regulatory milestones. With approval from the Arizona Corporation Commission (ACC), APS loaned funds to Pinnacle West Energy to relieve the debt burden incurred in the construction of new gas-fired power plants. We also completed a bidding process to secure more than 2,200 megawatts of capacity, including about 1,800 megawatts from Pinnacle West Energy's Arizona plants that were specifically built to serve APS customers. And our service area remained vibrant, as evidenced by customer growth of three times the national average and record levels of electricity consumption by our retail customers.

That growth, however, came at a price. Over the past few years, we've invested about $2 billion in new infrastructure to increase system reliability. In addition to expanding our generation portfolio, we completed a new 500-kilovolt transmission line from Palo Verde to the metropolitan Phoenix area. The 1,200-plus megawatt line played a significant role in APS' ability to avoid delivery problems during the summer of 2003.

To recover these and other costs – and as required by our 1999 Settlement Agreement with the ACC – we filed our first general rate case in more than a decade. This rate case covers our cost of service, return on equity, and fuel and purchased power adjustors. Just as important, it addresses a host of issues left unresolved when the ACC reversed its position on deregulation in 2002.

In 1999, we signed a regulatory agreement with the ACC that brought competitive choice to our customers, required us to transfer our APS power plants to an unregulated subsidiary and lowered prices by an average of 1.5 percent per year for five years. This agreement provided a foundation for Pinnacle West to form a business plan consistent with the ACC's wishes. It also explicitly recognized that our unregulated subsidiary could include our low-cost coal and nuclear units in one consolidated generating company.

In 2002, when the ACC reversed course and ordered us not to consolidate our power plants, we had been preparing for deregulation for nearly a decade. We built new gas-fired plants needed for APS customers in Arizona expecting they would be part of a much larger generation fleet that would include APS' fossil and nuclear units. As directed, we stopped course. But the ACC reversal changed everything, leaving many important issues open, including the financial integrity of those plants.

Because of unresolved issues – such as the critical need to consolidate our power plants going forward – our 2003 rate filing goes beyond a rate case. It's really about the future. In that sense, our current rate case is similar to our 1999 Settlement Agreement. The 1999 Settlement Agreement set out a path to the future. *That* future was the last five years and our performance was outstanding.

HOW FOCUSING ON THE FUTURE LED TO SUCCESS: 1999 TO 2003

Our future focus is not a new concept. In fact, it has been a necessity. During the last five years, we honed the traits that allowed us to navigate previously unseen industry volatility.

It took agility and adaptability. In 1999, like now, there was conflict between federal and state regulators, not to mention the unfettered presence of public power in the West. We insisted on keeping our existing power plants, and we didn't speculate in large merchant generation. We built much-needed new units to serve APS' new customers.

It took the ability to manage risk. Upon approval of the 1999 Settlement Agreement, we embarked upon a two-pronged approach to address customer reliability and price exposure. First, we announced the construction of 1,800 megawatts of new generation under Pinnacle West Energy to cover a portion of APS' needed generation. Second, we immediately began a short-term electric and natural gas hedging program to cover the interim period. We didn't panic and sign purchase power agreements at the peak of market prices, and our two-pronged approach allowed us to navigate the western fuel and power markets without harming customers or investors.

In the summer of 2000 and again in 2001, when wholesale power markets erupted, we were almost fully protected against price spikes with a combination of supply contracts, new generation and financial hedges. At no time did we dedicate the output of our new generation to anyone else.

It took commitment to meeting customer needs. We knew the generation capacity we would need wasn't going to be found in the wholesale marketplace. We were wary of the California market structure, so we fought from the very beginning against the divestiture of APS generation to a third party. We had envisioned what a decent wholesale market should look like and we didn't see one – and still don't – anywhere in the western United States.

Under the electric competition rules adopted by the ACC in 1999, we could not build any new generation at APS, and without new plants under construction we would have been forced to enter the wholesale energy market at the worst possible time. As our requests for proposals from the wholesale market have shown, no one else could have supplied the power our customers needed last year – and will need in the future – as economically as our new plants.

It took a focus on creating customer value. While other utilities were going bankrupt or passing along unheard-of price increases, we lowered our rates by 16 percent over a 10-year period. We delivered these price decreases,

as promised, and delivered the best customer satisfaction of any investor-owned utility in the West.

For the years 1999 through 2003, our peak demand grew nearly 25 percent. When combined with the 1,200-megawatt shortage APS had in 1999, APS' shortage grew to 2,500 megawatts, approximately one-third of our total responsibility. We met that shortage. During that time, we didn't have a single outage because of generation shortages or transmission congestion. We kept the lights on with outstanding operations – at our coal, nuclear and gas plants and throughout our "wires" organization.

It took a focus on creating shareholder value. We've proven adept at translating customer growth into financial results for our shareholders. While our market grew substantially, our workforce count remained flat. Since 1999, we've deployed more than $140 million of cash distributions from our real estate operations to improve liquidity and fund operating capital. Our common stock dividend growth over the last decade has been the best in our industry. And, the total return on our stock has consistently outpaced the S&P 500 Index.

WHY THE CURRENT RATE CASE IS SO IMPORTANT

We remain focused on the future, just as we were in 1999. But today we're in a state of regulatory transition, without sufficient structure to meet our rapidly growing customer demand. That regulatory structure is needed now so we can continue our outstanding performance for customers and investors.

The unresolved issues in the rate case we filed last year include consolidating Pinnacle West Energy's Arizona units into APS and restoring the $234 million write-off we were ordered to take as part of the 1999 Settlement Agreement. These issues, while important in themselves, point to the central regulatory issue confronting the ACC and this company – establishing the rules for the future.

In the past, we have been clear that a focus on the future required a firm grounding in regulatory consistency. We thought with the signing of the 1999 Agreement, we had achieved sufficient predictability and certainty, and we kept our commitments. With our agile approach to regulation and competition, we were able to secure the power we needed to keep the lights on, our customers satisfied and Arizona's economy running.

Today, that predictability and consistency are lacking. We have unfinished business, but we are confident we and our regulators can work together to re-establish a framework that balances customer value with investment risk and reward.

WHY THE FUTURE IS DEJA VU: 2004 TO 2008

Looking ahead, we're focused on ensuring that our company can build on its stellar performance of the last decade. To re-create our past successes – to make the long-term investment in infrastructure we will need in Arizona – requires a clear and consistent regulatory path. With that clarity in place, we will continue to:

Manage the future with agility and adaptability. Agility will always be fundamental. We will retain a sensitivity and responsiveness to the market and to regulatory uncertainty, which can be managed but never completely eliminated. And we'll remain focused on customer needs and Arizona's growth potential.

Utilize our risk management skills. We clearly know our way around western energy markets. Over the next five years, the skills we used to navigate the market storms of 2000 and 2001 will repeatedly prove their value. We will use every tool we possess to sidestep the ill effects of any future boom-bust cycle and protect our customers from market spikes.

Keep the lights on for our customers. We see no slowdown in customer growth, and likely a modest acceleration. To serve customers reliably, we must take action now, just as we made decisions in 1999 that gave us the power we needed. Our forecast shows we'll need about 1,800 more

megawatts of generating capacity by 2008, and a total of more than 3,000 by 2012. Those figures are in addition to the Pinnacle West Energy units we are asking to include in APS. That's why we issued a request for proposal late last year seeking additional capacity by 2007.

Our preference is to buy an existing station or build one ourselves. As long as power markets are rudimentary, illiquid and volatile, increasing reliance on the wholesale market presents unacceptable risk to customers and investors. But at present, we have no assurance that we would be allowed to recover the cost of a prudently planned and constructed plant.

Provide ongoing value for our customers. Providing value to our customers is the driving force of the people of our company. Through their dedication, creativity and commitment we will continue to achieve an enviable combination of price and service.

On the horizon, there are many exciting developments in technology, such as the "self-healing" grid, advances in metering and customer information, distributed generation, solar and other renewable energy sources. These new technologies, combined with the spirit of our people, will continue to produce excellent customer value.

Create shareholder value. For you, the owners of our company, we will continue to produce solid shareholder returns by capitalizing on our region's growth, concentrating on our core business and focusing on our future. We will continue to emphasize dividends, while striving to achieve a regulatory structure that recognizes the importance of aligning investment expectations with potential returns.

WHY THE FUTURE IS NOW

We are poised to become a new kind of vertically integrated utility – one that provides customers with reliable power at a reasonable price but remains subject to the discipline of the energy marketplace. A utility that uses its skills to navigate the energy market for the benefit of both customers and investors.

As I said in last year's Annual Report letter, competition and regulation will co-exist and we must operate effectively in both worlds. The fundamental forces of market structure, electric reliability, customer value and investment risk/reward will shape the consistency and alignment between the two, and as a new kind of vertically integrated utility we must anticipate their evolution. Since competitive markets often move faster than regulation, it's imperative that the regulatory structure considers the future, and that regulators go beyond traditional, historical regulation.

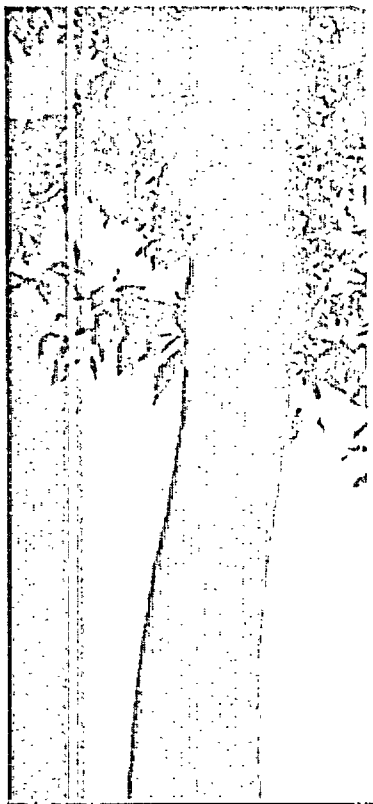
Our Arizona regulators recognize the absolute need to manage electric reliability and price volatility on behalf of customers and the importance of a financially solid electric utility. The regulatory decisions needed in 2004 are critical to the foundation of operating and resource decisions we must make now for 2008 and beyond. I believe our commissioners understand the long-term need to have a reliable and affordable electric infrastructure as a base to fuel Arizona's economy.

Resolving our current rate case fairly means balancing customer and shareholder interests by recognizing that those interests are frequently aligned. Over the long term, a financially strong utility and low customer rates go hand-in-hand.

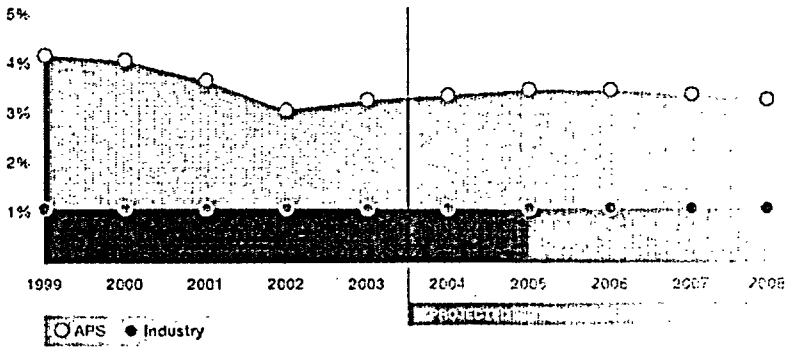
We are committed to achieving a regulatory outcome that sets a firm foundation for important operating and resource decisions. Simultaneously, we will continue to meet our customers' growing needs, improve service levels, build on our excellent operating performance and manage our resources in a safe and ethical manner while providing our shareholders a fair return on their investment.

This is our hallmark.

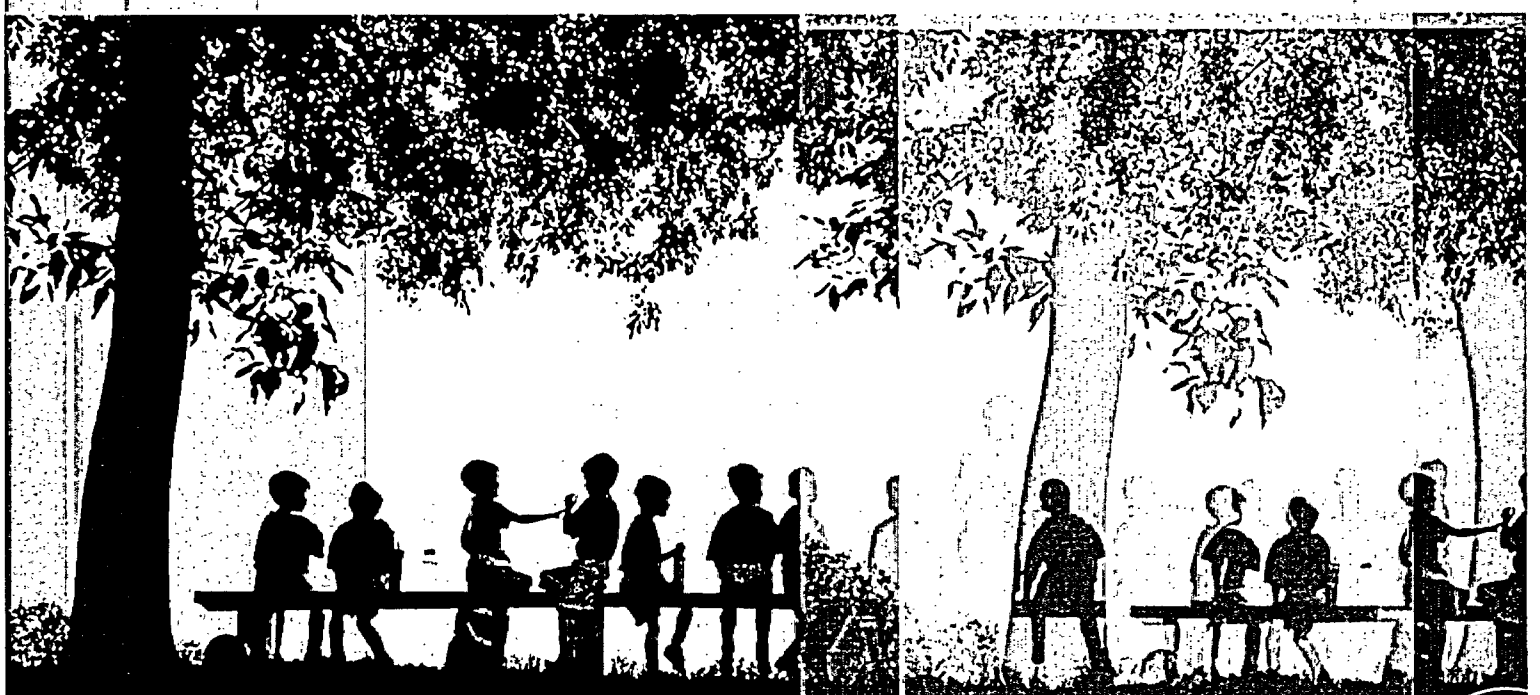
William J. Post, Chairman



APS RETAIL CUSTOMER GROWTH 1999 TO 2008



Our customer base will continue to grow rapidly – about three times the industry average.

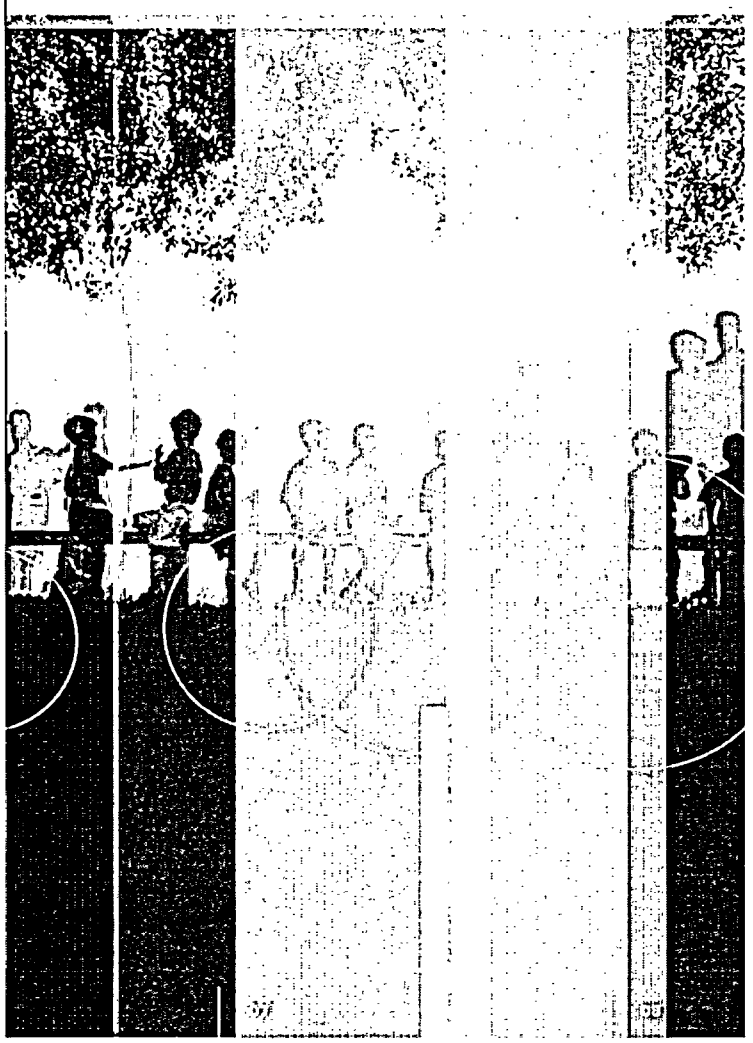


LOOKING AHEAD_ growth 2008

APS' unique customer growth continues to be the envy of the industry. By the end of 2008 the company adds about 170,000 new customers, and serves a total of more than 1.1 million Arizona customers. Electric system peak load expands as well, growing by about 25 percent.

Whether 2003 or 2008, customer growth is the fuel that powers our industry's financial engine. In this area, APS has few peers. In 2003, our customer growth was again rapid and unique. APS experienced 3.3 percent customer growth (roughly 30,000 new customers). This was about three times the industry average.

The epicenter of this growth is found in the heart of our service territory – the Greater Phoenix area. In 2003, approximately 3.4 million residents called the Phoenix area home – a 17 percent increase from just five years earlier. In 2003, the Phoenix metro area also issued more than 47,000 building permits, the highest number of permits in the last 18 years.



Of course, growth benefits the company's bottom line only if it is met with sufficient resources. In 2003, our company completed a 530-megawatt unit at the West Phoenix Power Plant. By the end of 2004, the company will have added nearly 2,400 megawatts of new generating capacity (including about 1,800 megawatts in Arizona) in the last four years.

In addition to increasing our generating capabilities, we continue to expand our transmission and distribution system. In 2003, we energized a new 37-mile 500-kilovolt transmission line that runs from the Palo Verde Nuclear Generating Station to the Phoenix area. Completion of the line allowed more than 1,200 megawatts of additional power to flow into Arizona's largest metropolitan area and played a vital role in APS' ability to avoid severe delivery problems during the summer of 2003.

Renewable energy resources will clearly be a large part of Arizona's energy future. Construction is currently underway on the Prescott (Ariz.) Airport Solar Power Plant, which will be one of the largest photovoltaic solar plants in the world. We are also a major participant in a new biomass plant in northeastern Arizona, which can take the by-products of negative situations – Arizona's vast Rodeo-Chedeski fires of 2002 and our state's devastating bark beetle infestation – and convert them into fuel. Most recently, APS announced it will partner with Western Wind Energy Corporation to establish Arizona's first commercial wind farm.

No other electric utility in the U.S. can match our dividend growth over the last 10 years. In that period, Pinnacle West's average dividend growth rate was 8.4 percent per year, ranking us number one industry-wide. In 2003, our annual dividend was increased 10 cents per share for the 10th consecutive year. We recognize that dividends underpin stock performance. Our track record in growing our dividend has been a distinguishing investment characteristic for our company.

Just as Pinnacle West's previous planning efforts played a vital role in 2003, today's planning will help ensure the successes and manage the challenges of 2006.

As required by a 1999 Settlement Agreement approved by the Arizona Corporation Commission, APS filed a general rate case in mid-2003 – our first in well over a decade. That filing requested a 9.8 percent retail revenue increase, which would be the company's first price increase in more than 13 years. Even with the requested increase, APS' rates would be about 6 percent below what they were in 1993.

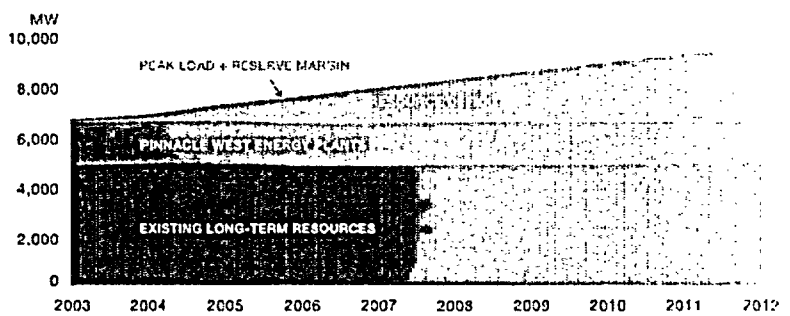
Through the regulatory process, our goal is to find a workable structure that helps ensure long-term reliability and price stability for our customers, and supports continuing growth in the state of Arizona while providing a reasonable return for our shareholders.

In 2003, APS implemented the last of a series of rate reductions that have lowered customer prices an average of 16 percent since 1993. This decrease represented the largest cumulative price decrease among investor-owned utilities nationwide during that time period, and saved our customers well over $1 billion.

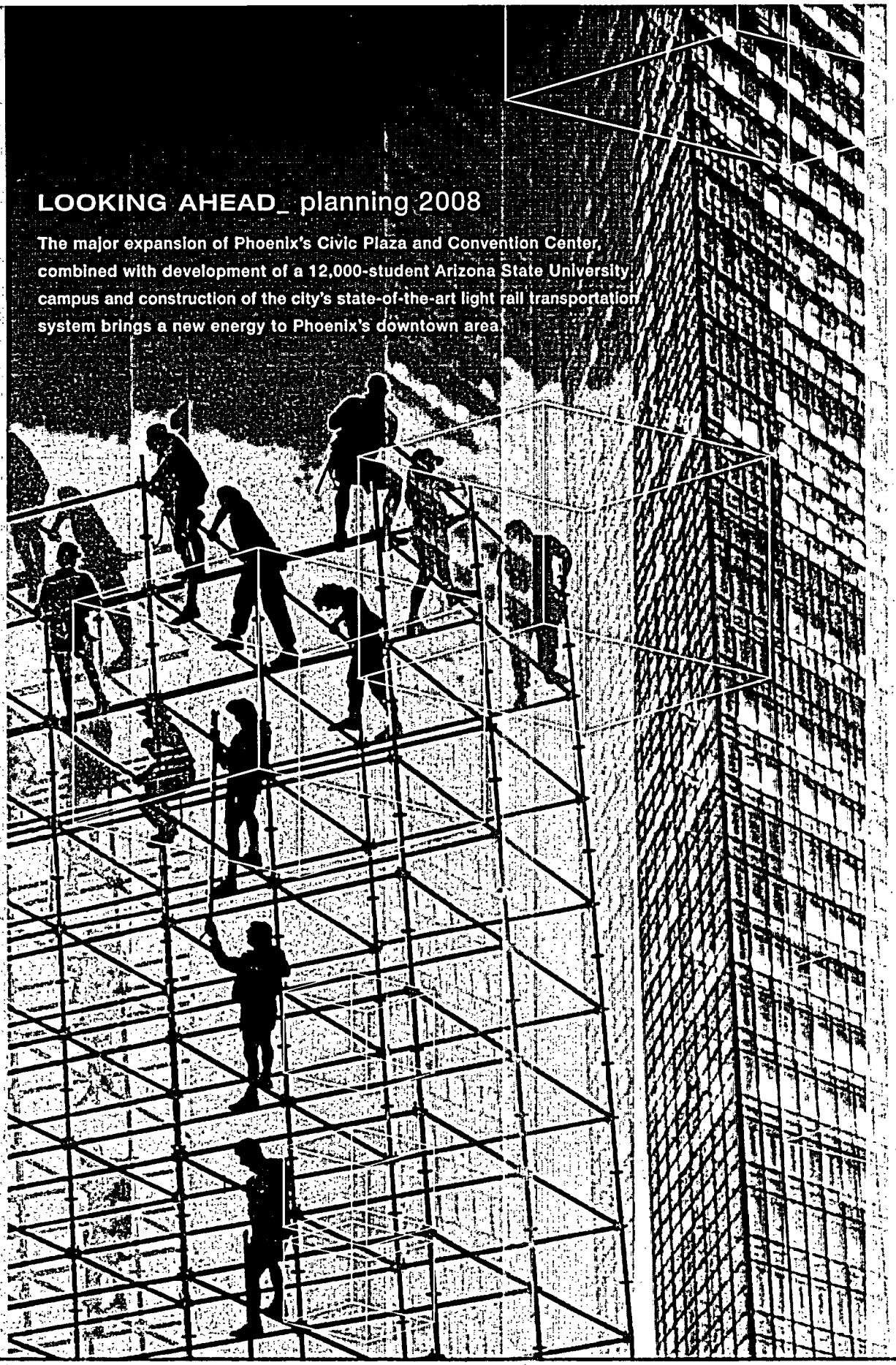
Providing reliable electricity is at the top of our agenda as we plan for Arizona's energy future. As APS' customer base has grown, individual energy usage has also risen dramatically. From 1991 to 2003, household usage of electricity in Arizona has increased an average of 23 percent. In 2003, APS' peak energy load demand rose more than 9 percent over the previous year. APS' peak load, over the last two years, has grown more than 600 megawatts, approximately equal to the output of one of our units at our new Redhawk Power Plant.

We completed a large-scale maintenance project at the Palo Verde Nuclear Generating Station in the fall of 2003, to improve the efficiency and reliability of our lowest-cost power source. Two 800-ton steam generators were successfully replaced in Unit 2, completing more than five years of planning and careful management of the manufacture and transportation of the generators from Italy. During the replacement process, plant employees set a world record for the lowest collective radiation exposure during a steam generator replacement.

APS ELECTRIC SYSTEM LOAD AND RESOURCES 2003 TO 2012



Moving forward, our customer demand will grow, and so will our need for new power resources.



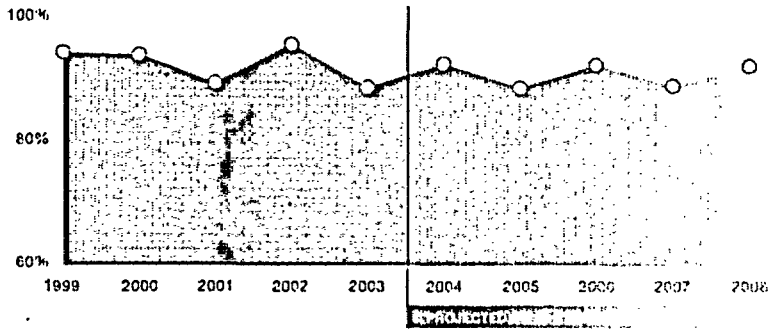
LOOKING AHEAD_ planning 2008

The major expansion of Phoenix's Civic Plaza and Convention Center, combined with development of a 12,000-student Arizona State University campus and construction of the city's state-of-the-art light rail transportation system brings a new energy to Phoenix's downtown area.

LOOKING AHEAD_ performance 2008

New transmission technology is pioneered that allows the company to increase electric conductor capacity in its transmission lines. The new technology allows the lines to handle increased power flow, providing greater energy efficiency.

APS NUCLEAR GENERATION CAPACITY FACTOR 1999 TO 2008



Our nuclear generation performance has consistently outpaced the industry

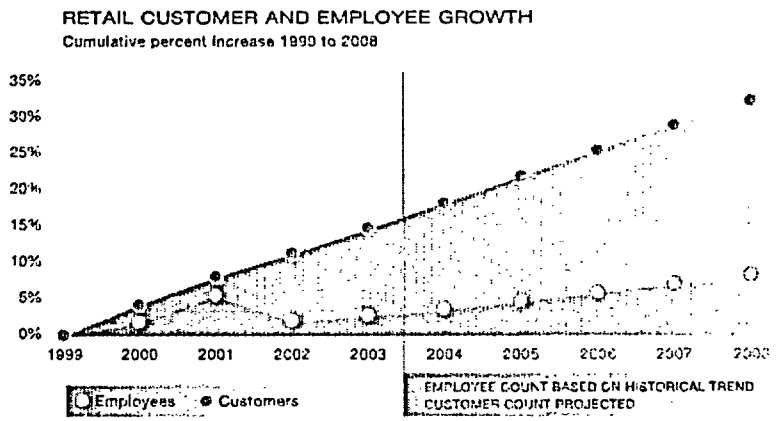
It's likely that in our 117 years as a company, no employees have been asked to accomplish more than our current staff. They are the embodiment of "doing more with less." In the last five years, APS has added more than 150,000 customers, while our workforce numbers have remained virtually the same. Added demands have pushed us to find ways to work more efficiently. The result has been an energetic, innovative and purposeful workforce.

One example of our company's strong productivity comes from the Palo Verde Nuclear Generating Station west of Phoenix. In 2003, Palo Verde marked its 12th consecutive year as the largest power producer of any kind in the United States.

In addition, our gas-fired plants – including our new units at West Phoenix and Redhawk – operated at about 90 percent availability, and the combined capacity factor for our Four Corners and Cholla power plants ranked near the top of the industry.

Taking advantage of opportunities in a favorable real estate market, SunCor Development Co., Pinnacle West's real estate subsidiary, delivered solid performance, reporting 2003 net income of $56 million, compared with net income of $19 million for 2002. SunCor's performance is expected to augment the company's earnings pending the outcome of APS' rate case.

APS Energy Services continued to deliver solid earnings, while building a stellar customer reputation. Commodity electricity sales to key California businesses and government customers remained strong, and the company saw significant growth in energy services and energy efficiency sales in Arizona, California and Nevada. Northwind, the company's district cooling and heating operations expanded from downtown Phoenix, adding operation of a site in Tucson, Ariz.



Our employees continue to serve more customers, more efficiently.

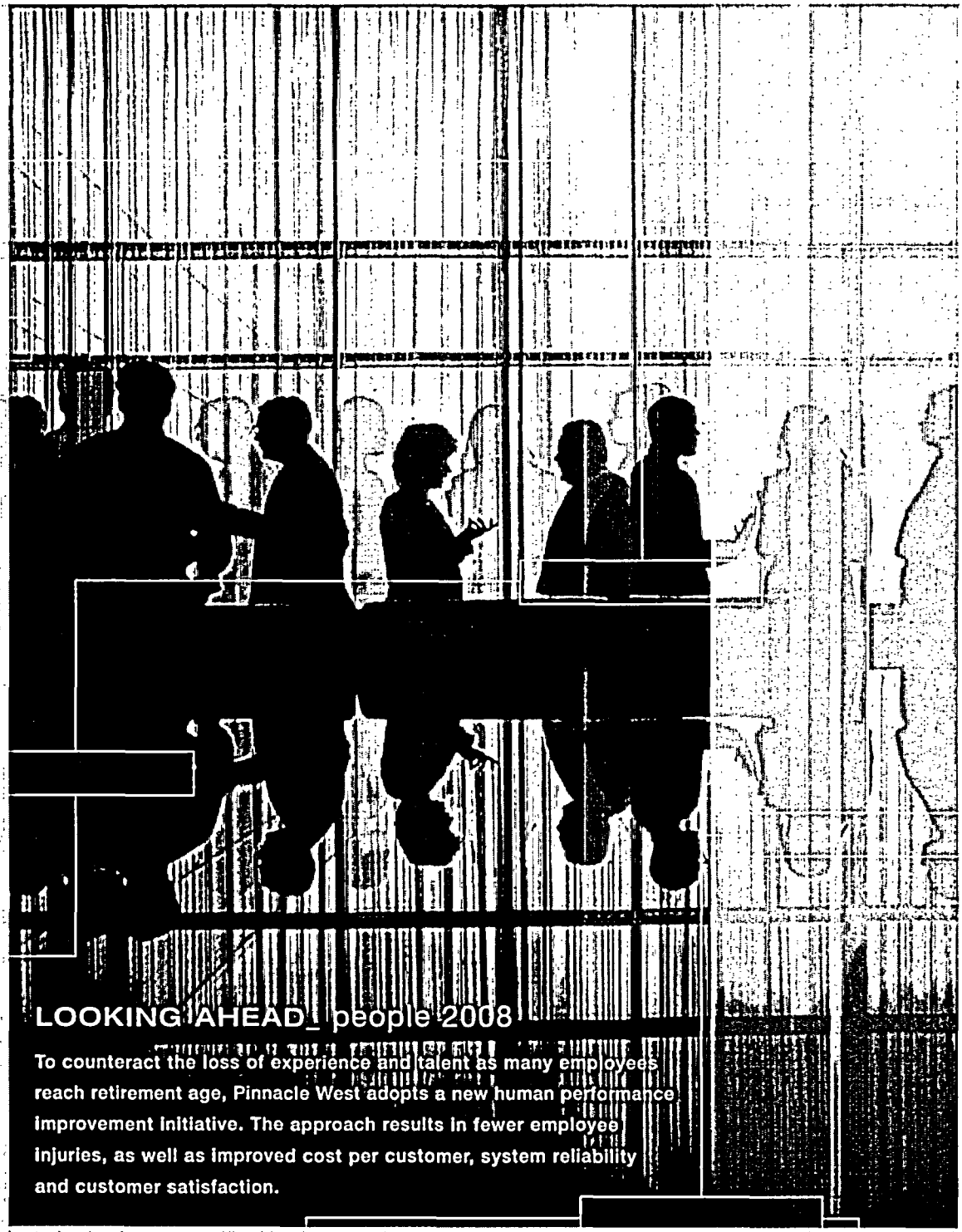
Focusing on the needs of customers has resulted in steadily improving customer satisfaction scores as measured by the J.D. Power and Associates Electric Utility Residential Customer Satisfaction Study. In 2003, APS ranked second among electric utilities in the West, and earned the highest score among investor-owned utilities in the region. APS improved its scores in all five of the survey's factors, which measure customer attitudes about power quality and reliability, company image, price and value, billing and payment, and customer service.

Our utility Web site – aps.com – continues to reduce operating costs, while providing customers another convenient way to work with our company. Customers can connect and disconnect their service, receive and pay their electricity bills and get helpful information online. The site handles more than 70,000 payments each month, far surpassing company goals. Such performance helped the site earn its second consecutive Best Energy Web Site WebAward from the Web Marketing Association, a national organization of Internet marketing, advertising, public relations and design professionals.

A company-wide emphasis on safety in 2003 resulted in decreased preventable recordable injuries – the third such reduction in as many years. Employees at the West Phoenix and Yucca power plants contributed to this improvement by working 22 and 19 years, respectively, without a lost-time accident.

Dedication to a safe and healthy workforce is one of the reasons Pinnacle West earned a spot on AARP's list of "Best Employers for Workers Over 50." The advocacy organization recognized the company's efforts to retain older employees by promoting continuing education and flexible schedules. Pinnacle West was one of two Arizona employers on the national list.

We take a very broad view of business performance, which includes not only earnings and stock price, but also the value of safety, environmental and social performance, customer service and integrity. In 2003, our performance in these areas earned Pinnacle West a "10" rating, on a scale of 1 to 10, from governance ratings agency GovernanceMetrics International, which ranked 1,000 U.S. electric utilities in the area of Corporate Governance.



LOOKING AHEAD_ people 2008

To counteract the loss of experience and talent as many employees reach retirement age, Pinnacle West adopts a new human performance improvement initiative. The approach results in fewer employee injuries, as well as improved cost per customer, system reliability and customer satisfaction.

2003 Consolidated Financial Information

SELECTED CONSOLIDATED FINANCIAL DATA (dollars in thousands, except shares and per share amounts)

	2003	2002	2001	2000	1999
OPERATING RESULTS					
Operating revenues:					
Regulated electricity segment (a)	$ 1,978,075	$ 1,890,391	$ 1,984,305	$ 2,536,752	$ 1,915,108
Marketing and trading segment (a)	391,866	286,679	469,784	416,532	154,125
Real estate segment	361,604	201,081	168,908	158,365	130,169
Other revenues	86,287	61,937	11,771	3,873	439
Income from continuing operations	$ 230,576	$ 206,198	$ 327,367	$ 302,332	$ 269,772
Discontinued operations – net of income taxes (b) (c)	10,003	8,955	–	–	38,000
Extraordinary charge – net of income taxes (d)	–	–	–	–	(139,885)
Cumulative effect of change in accounting – net of income taxes (e) (f)	–	(65,745)	(15,201)	–	–
Net income	$ 240,579	$ 149,408	$ 312,166	$ 302,332	$ 167,887
COMMON STOCK DATA					
Book value per share – year-end	$ 30.97	$ 29.40	$ 29.46	$ 28.09	$ 26.00
Earnings (loss) per weighted average common share outstanding:					
Continuing operations – basic	$ 2.53	$ 2.43	$ 3.86	$ 3.57	$ 3.18
Discontinued operations	0.11	0.10	–	–	0.45
Extraordinary charge	–	–	–	–	(1.65)
Cumulative effect of change in accounting	–	(0.77)	(0.18)	–	–
Net income – basic	$ 2.64	$ 1.76	$ 3.68	$ 3.57	$ 1.98
Continuing operations – diluted	$ 2.52	$ 2.43	$ 3.85	$ 3.56	$ 3.17
Net income – diluted	$ 2.63	$ 1.76	$ 3.68	$ 3.56	$ 1.97
Dividends declared per share	$ 1.725	$ 1.625	$ 1.525	$ 1.425	$ 1.325
Indicated annual dividend rate per share – year-end	$ 1.80	$ 1.70	$ 1.60	$ 1.50	$ 1.40
Weighted-average common shares outstanding – basic	91,264,696	84,902,946	84,717,649	84,732,544	84,717,135
Weighted-average common shares outstanding – diluted	91,405,134	84,963,921	84,930,140	84,935,282	85,008,527
BALANCE SHEET DATA					
Total assets	$ 9,536,378	$ 9,139,157	$ 8,529,124	$ 7,697,558	$ 7,095,441
Liabilities and equity:					
Long-term debt less current maturities	$ 2,897,725	$ 2,743,741	$ 2,673,078	$ 1,955,083	$ 2,206,052
Other liabilities	3,808,874	3,709,263	3,356,723	3,359,761	2,683,656
Total liabilities	6,706,599	6,453,004	6,029,801	5,314,844	4,889,708
Common stock equity	2,829,779	2,686,153	2,499,323	2,382,714	2,205,733
Total liabilities and equity	$ 9,536,378	$ 9,139,157	$ 8,529,124	$ 7,697,558	$ 7,095,441

(a) Includes reclassifications of revenues in 2003, 2002 and 2001 for the adoption of EITF 03-11. See Note 15 of Notes to Consolidated Financial Statements.
(b) Tax benefit stemming from the resolution of income tax matters related to a former subsidiary, MeraBank, A Federal Savings Bank in 1999.
(c) Real estate discontinued operations in 2003 and 2002. See Note 22 of Notes to Consolidated Financial Statements.
(d) Charges associated with a regulatory disallowance. See "Regulatory Accounting" in Note 1 of Notes to Consolidated Financial Statements.
(e) Change in accounting standards related to derivatives in 2001. See Note 18 of Notes to Consolidated Financial Statements.
(f) Change in accounting standards related to energy trading activities in 2002. See Note 18 of Notes to Consolidated Financial Statements.

QUARTERLY STOCK PRICES AND DIVIDENDS PER SHARE Stock Symbol: PNW

2003	High	Low	Close	Dividends Per Share	2002	High	Low	Close	Dividends Per Share
1st Quarter	$ 37.13	$ 28.34	$ 33.24	$ 0.425	1st Quarter	$ 45.60	$ 39.36	$ 45.35	$ 0.400
2nd Quarter	39.59	31.35	37.45	0.425	2nd Quarter	46.68	37.08	39.50	0.400
3rd Quarter	38.03	32.67	35.50	0.425	3rd Quarter	39.72	25.82	27.76	0.400
4th Quarter	40.48	34.91	40.02	0.450	4th Quarter	34.36	21.70	34.09	0.425

GLOSSARY

ACC – Arizona Corporation Commission
ADEQ – Arizona Department of Environmental Quality
AFUDC – allowance for funds used during construction
ALJ – Administrative Law Judge
ANPP – Arizona Nuclear Power Project, also known as Palo Verde
APS – Arizona Public Service Company, a subsidiary of the Company
APS Energy Services – APS Energy Services Company, Inc., a subsidiary of the Company
CC&N – Certificate of Convenience and Necessity
Cholla – Cholla Power Plant
Citizens – Citizens Communications Company
Clean Air Act – the Clean Air Act, as amended
Company – Pinnacle West Capital Corporation
CPUC – California Public Utility Commission
DOE – United States Department of Energy
EITF – the FASB's Emerging Issues Task Force
El Dorado – El Dorado Investment Company, a subsidiary of the Company
EPA – United States Environmental Protection Agency
ERMC – the Company's Energy Risk Management Committee
FASB – Financial Accounting Standards Board
FERC – United States Federal Energy Regulatory Commission
FIN – FASB Interpretation
Financing Order – ACC Order that authorized APS' $500 million loan to Pinnacle West Energy in May 2003
Four Corners – Four Corners Power Plant
GAAP – accounting principles generally accepted in the United States of America
IRS – United States Internal Revenue Service
ISO – California Independent System Operator
kW – kilowatt, one thousand watts
kWh – kilowatt-hour, one thousand watts per hour
Moody's – Moody's Investors Service
MW – megawatt, one million watts
MWh – megawatt-hours, one million watts per hour
NAC – NAC International Inc., a subsidiary of El Dorado
Native Load – retail and wholesale sales supplied under traditional cost-based rate regulation
1999 Settlement Agreement – comprehensive settlement agreement related to the implementation of retail electric competition
NRC – United States Nuclear Regulatory Commission
Nuclear Waste Act – Nuclear Waste Policy Act of 1982, as amended
OCI – other comprehensive income
Palo Verde – Palo Verde Nuclear Generating Station
PCAOB – Public Company Accounting Oversight Board
PG&E – PG&E Corp.
Pinnacle West – Pinnacle West Capital Corporation, the Company
Pinnacle West Energy – Pinnacle West Energy Corporation, a subsidiary of the Company
PWEC Dedicated Assets – the following Pinnacle West Energy power plants, each of which is dedicated to serving APS' customers: Redhawk Units 1 and 2, West Phoenix Units 4 and 5 and Saguaro Unit 3
PX – California Power Exchange
Rules – ACC retail electric competition rules
Salt River Project – Salt River Project Agricultural Improvement and Power District
SCE – Southern California Edison Company
SEC – United States Securities and Exchange Commission
SFAS – Statement of Financial Accounting Standards
SNWA – Southern Nevada Water Authority
SPE – special-purpose entity
Standard & Poor's – Standard & Poor's Corporation
SunCor – SunCor Development Company, a subsidiary of the Company
T&D – transmission and distribution
Track A Order – ACC order dated September 10, 2002 regarding generation asset transfers and related issues
Track B Order – ACC order dated March 14, 2003 regarding competitive solicitation requirements for power purchases by Arizona's investor-owned electric utilities
Trading – energy-related activities entered into with the objective of generating profits on changes in market prices
VIE – variable interest entity

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

INTRODUCTION

The following discussion should be read in conjunction with the Consolidated Financial Statements and the related Notes.

OVERVIEW

We own all of the outstanding common stock of APS. APS is a vertically integrated electric utility that provides either retail or wholesale electric service to substantially all of the state of Arizona, with the major exceptions of the Tucson metropolitan area and about one-half of the Phoenix metropolitan area. Through its marketing and trading division, APS also generates, sells and delivers electricity to wholesale customers in the western United States. APS has historically accounted for a substantial part of our revenues and earnings. Growth in APS' service territory is about three times the national average and remains a fundamental driver of our revenues and earnings.

Pinnacle West Energy is our unregulated generation subsidiary. We formed Pinnacle West Energy in 1999 as a result of the ACC's requirement that APS transfer all of its competitive assets and services to an affiliate or to a third party by the end of 2002. We planned to transfer APS' generation assets to Pinnacle West Energy. Additionally, Pinnacle West Energy constructed several power plants to meet growing energy needs (1790 MW in Arizona and 570 MW in Nevada). In September 2002, the ACC issued the Track A Order, which prohibited APS from transferring its generation assets to Pinnacle West Energy. As a result of the Track A Order, we are seeking to transfer the plants built by Pinnacle West Energy in Arizona to APS to unite the Arizona generation under one common owner, as originally intended.

SunCor, our real estate development subsidiary, has been and is expected to be an important source of earnings and cash flow, particularly during the years 2003 through 2005 due to accelerated asset sales activity. Our subsidiary, APS Energy Services, provides competitive commodity-related energy services and energy-related products and services to commercial, industrial and institutional retail customers in the western United States.

The earnings contributions of our marketing and trading segment significantly decreased over the past two years due to lower market liquidity and deteriorating counterparty credit in the wholesale power markets in the western United States. The marketing and trading division focuses primarily on managing APS' purchased power and fuel risks in connection with APS' costs of serving retail customer energy requirements. We currently expect contributions from our trading activities to be negligible for 2004 and approximately $10 million (pretax) annually thereafter.

We continue to focus on solid operational performance in our electricity generation and delivery activities. In the generation area, 2003 represented the twelfth consecutive year Palo Verde was the largest power producer in the United States. In the delivery area, we focus on superior reliability and expanding our transmission and distribution system to meet growth and sustain reliability.

We believe APS' general rate case pending before the ACC is the key issue affecting our outlook. As discussed in greater detail in Note 3, in this rate case APS has requested, among other things, a 9.8% retail rate increase (approximately $175 million annually) rate treatment for the PWEC Dedicated Assets and the recovery of $234 million written off by APS as part of the 1999 Settlement Agreement. In its filed testimony, the ACC staff recommended, among other things, that the ACC decrease APS' rates by approximately 8% (approximately $143 million annually), not allow the PWEC Dedicated Assets to be included in APS' rate base, and not allow APS to recover any of the $234 million written off as a result of the 1999 Settlement Agreement. The ACC staff recommendations, if implemented as proposed, could have a material adverse impact on our results of operations, financial position, liquidity, dividend sustainability, credit ratings and access to capital markets. We believe that APS' rate case requests are supported by, among other things, APS' demonstrated need for the PWEC Dedicated Assets; APS' need to attract capital at reasonable rates of return to support the required capital investment to ensure continued customer reliability in APS' high-growth service territory; and the conditions in the western energy market. As a result, we believe it is unlikely that the ACC would adopt the ACC staff recommendations in their present form, although we can give no assurances in that regard. The hearing on the rate case is scheduled to begin on May 25, 2004. We believe the ACC will be able to make a decision by the end of 2004.

Other factors affecting our past and future financial results include customer growth; purchased power and fuel costs; operations and maintenance expenses, including those relating to plant outages; weather variations; depreciation and amortization expenses, which are affected by net additions to existing utility plant and other property and changes in regulatory asset amortization; and the expected performance of our subsidiaries, SunCor and El Dorado.

EARNINGS CONTRIBUTIONS BY SUBSIDIARY AND BUSINESS SEGMENTS

We have three principal business segments (determined by products, services and the regulatory environment):

- our regulated electricity segment, which consists of traditional regulated retail and wholesale electricity businesses and related activities and includes electricity generation, transmission and distribution;

- our marketing and trading segment, which consists of our competitive energy business activities, including wholesale marketing and trading and APS Energy Services' commodity-related energy services. In early 2003, we moved our marketing and trading activities to APS from Pinnacle West (existing wholesale contracts remained at Pinnacle West) as a result of the ACC's Track A Order prohibiting the previously required transfer of APS' generating assets to Pinnacle West Energy; and
- our real estate segment, which consists of SunCor's real estate development and investment activities.

The following tables summarize net income and segment details for the years ended December 31, 2003, 2002 and 2001 for Pinnacle West and each of our subsidiaries (dollars in millions):

2003	TOTAL	Regulated Electricity	Marketing and Trading	Real Estate(a)	Other(b)
APS (c)	$ 181	$ 184	$ (3)	$ –	$ –
Pinnacle West Energy (c)	(1)	–	(1)	–	–
APS Energy Services	16	–	13	–	3
SunCor	46	–	–	46	–
El Dorado (principally NAC) (d)	7	–	–	–	7
Parent company (d)	(18)	(14)	–	(1)	(3)
Income from continuing operations	231	170	9	45	7
Income from discontinued operations – net of income taxes	10	–	–	10	–
Net income	$ 241	$ 170	$ 9	$ 55	$ 7

2002	TOTAL	Regulated Electricity	Marketing and Trading	Real Estate(a)	Other(b)
APS (c)	$ 199	$ 196	$ 1	$ –	$ –
Pinnacle West Energy (c) (e)	(19)	(21)	2	–	–
APS Energy Services (d)	26	–	23	–	5
SunCor	10	–	–	10	–
El Dorado (principally NAC) (d)	(55)	–	–	–	(55)
Parent company (d)	43	(7)	32	–	18
Income (loss) from continuing operations	206	170	58	10	(32)
Income from discontinued operations – net of income taxes	9	–	–	9	–
Cumulative effect of change in accounting – net of income taxes (f)	(66)	–	(66)	–	–
Net income (loss)	$ 149	$ 170	$ (8)	$ 19	$ (32)

2001	TOTAL	Regulated Electricity	Marketing and Trading	Real Estate(a)	Other
APS (c)	$ 281	$ 139	$ 142	$ –	$ –
Pinnacle West Energy (c)	18	18	–	–	–
APS Energy Services (d)	(10)	–	(11)	–	1
SunCor	3	–	–	3	–
El Dorado (d)	–	–	–	–	–
Parent company (d)	35	(5)	40	–	–
Income before accounting change	327	152	171	3	1
Cumulative effect of change in accounting – net of income taxes (g)	(15)	(15)	–	–	–
Net income	$ 312	$ 137	$ 171	$ 3	$ 1

(a) See Note 22, "Real Estate Activities – Discontinued Operations."

(b) The "Other" segment primarily includes activities related to El Dorado's investment in NAC. We recorded pretax losses of $59 million in 2002, primarily related to NAC contracts with three customers.

(c) Consistent with APS' October 2001 ACC filing, APS entered into contracts with its affiliates to buy power through June 2003. The contracts reflected prices based on the fully-dispatchable dedication of the PWEC Dedicated Assets to APS' Native Load customers (customers receiving power under traditional cost-based rate regulation). Beginning July 1, 2003, under the ACC Track B Order, APS was required to solicit bids for certain estimated capacity and energy requirements. Pinnacle West Energy bid and entered into a contract to supply most of these purchase power requirements in summer months through September 2006. See "Track B Order" in Note 3 for more information.

(d) APS Energy Services' net income prior to 2003 and El Dorado's net income (loss) are primarily reported before income taxes. The income tax expense or benefit for these subsidiaries is recorded at the parent company.

(e) In the fourth quarter of 2002 Pinnacle West Energy recorded a charge related to the cancellation of Redhawk Units 3 and 4 of approximately $30 million after income taxes ($49 million pretax).

(f) As of October 1, 2002, we recorded a $66 million after-tax charge for the cumulative effect of a change in accounting for trading activities, for the early adoption of EITF 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities." See Note 18.

(g) APS recorded a $15 million after-tax charge in 2001 for the cumulative effect of a change in accounting for derivatives related to the adoption of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." See Note 18.

See Note 17 for additional financial information regarding our business segments.

RESULTS OF OPERATIONS

General

Throughout the following explanations of our results of operations, we refer to "gross margin." With respect to our regulated electricity segment and our marketing and trading segment, gross margin refers to electric operating revenues less purchased power and fuel costs. Our real estate segment gross margin refers to real estate revenues less real estate operations costs of SunCor. Other gross margin refers to other operating revenues less other operating expenses, which primarily includes El Dorado's investment in NAC, which we began consolidating in our financial statements in July 2002. Other gross margin also includes amounts related to APS Energy Services' energy consulting services. In addition, we have reclassified certain prior period amounts to conform to our current period presentation, including netting of certain revenues and purchased power amounts as a result of the adoption of EITF 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not 'Held for Trading Purposes' As Defined in Issue No. 02-3" (see Note 18).

2003 Compared with 2002

Our consolidated net income for the year ended December 31, 2003 was $241 million compared with $149 million for the prior year. The 2002 net income includes a $66 million after-tax charge for the cumulative effect of a change in accounting for trading activities due to the adoption of EITF 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities" (see Note 18). Excluding the accounting change, the $26 million increase in the period-to-period comparison reflects the following changes in earnings by segment:

- Regulated Electricity Segment – Net income was flat when comparing the two years, due to offsetting factors. Net income in 2003 was negatively impacted by higher purchased power and fuel costs resulting from higher prices for hedged gas and purchased power; higher costs related to new power plants, net of purchased power savings; higher replacement power costs from plant outages due to higher market prices and more unplanned outages (Unit 3 of the Cholla Power Plant experienced an unplanned outage from August 3, 2003 through November, 2003 and Units 1 and 2 of the Redhawk Power Plant were substantially restricted for almost one-half of the fourth quarter to correct an equipment design defect); higher operations and maintenance costs related to increased pension and other benefits; two retail electricity price reductions; and higher depreciation expense related to increased delivery and other assets. These negative factors were offset by higher retail sales primarily due to customer growth and favorable weather; the absence of the 2002 write-off of Redhawk Units 3 and 4; lower operating costs primarily related to severance costs recorded in 2002; lower regulatory asset amortization; tax credits and favorable income tax adjustments related to prior years resolved in 2003; and higher income related to APS' return to the AFUDC method of capitalizing construction finance costs.
- Marketing and Trading Segment – Income from continuing operations decreased approximately $49 million primarily due to lower market liquidity and deteriorating counterparty credit in the wholesale power markets in the western United States.
- Real Estate Segment – Net income improved approximately $36 million primarily due to increased asset, land and home sales.
- Other Segment – Net income increased approximately $39 million primarily due to NAC losses recognized in 2002.

Additional details on the major factors that increased (decreased) income from continuing operations and net income for the year ended December 31, 2003 compared with the prior year are contained in the following table (dollars in millions).

	Increase/(Decrease)	
	Pretax	After Tax
Regulated electricity segment gross margin:		
Increased purchased power and fuel costs primarily due to higher prices for hedged gas and purchased power	$ (60)	$ (36)
Higher replacement power costs from plant outages due to higher market prices and more unplanned outages	(47)	(28)
Retail electricity price reductions effective July 1, 2002 and July 1, 2003	(27)	(16)
Higher retail sales volumes due to customer growth, excluding weather effects	48	29
Decreased purchased power costs due to new power plants in service	16	10
Effects of weather on retail sales	13	8
Miscellaneous factors, net	5	2
Net decrease in regulated electricity segment gross margin	(52)	(31)
Marketing and trading segment gross margin:		
Lower mark-to-market gains for future delivery due to lower market liquidity and deteriorating counterparty credit	(59)	(35)
Lower realized margins on wholesale sales primarily due to lower unit margins, partially offset by higher volumes	(32)	(19)
Higher margin related to structured contracts originated in prior years	13	7
Decrease in generation sales other than Native Load primarily due to lower unit margins partially offset by higher sales volumes, including sales from new power plants in service	(7)	(4)
Net decrease in marketing and trading segment gross margin	(85)	(51)
Net decrease in regulated electricity and marketing and trading segments' gross margins	(137)	(82)
Higher income primarily related to NAC losses recognized in 2002	66	40
Higher real estate segment contribution primarily due to higher asset, land and home sales	58	36
Operations and maintenance expense decreases (increases):		
Write-off of Redhawk Units 3 and 4 in 2002	47	28
Severance costs recorded in 2002	36	21
Increased pension and other benefit costs	(28)	(17)
Costs for new power plants in service	(20)	(12)
Net other items	1	1
Higher interest expense and lower capitalized interest primarily related to new power plants in service	(26)	(16)
Depreciation and amortization decreases (increases):		
New power plants in service	(19)	(11)
Increased delivery and other assets	(24)	(14)
Decreased regulatory asset amortization	29	17
APS' return to the AFUDC method of capitalizing construction finance costs	8	11
Miscellaneous items, net	7	7
Tax credits and favorable income tax adjustments related to prior years resolved in 2003	–	17
Net (decrease)/increase in income from continuing operations	$ (2)	26
Increase due to 2002 cumulative effect of a change in accounting for trading activities – net of income taxes		66
Net increase in net income		$ 92

The increase in operating and interest costs related to new power plants placed in service by Pinnacle West Energy, net of purchased power savings and increased gross margin from generation sales other than Native Load, totaled approximately $30 million after income taxes in the year ended December 31, 2003 compared with the prior-year period.

Regulated Electricity Segment Revenues

Regulated electricity segment revenues were $68 million higher in the year ended December 31, 2003 compared with the prior year, primarily as a result of:

- an $85 million increase in retail revenues related to customer growth and higher average usage, excluding weather effects;
- a $21 million increase in retail revenues related to weather;
- a $6 million increase related to traditional wholesale sales as a result of higher prices and higher sales volumes;
- a $27 million decrease in retail revenues related to two reductions in retail electricity prices; and
- a $3 million net increase due to miscellaneous factors.

Marketing and Trading Segment Revenues

Marketing and trading segment revenues were $105 million higher in the year ended December 31, 2003 compared with the prior year, primarily as a result of:

- $74 million of higher revenues related to the adoption of EITF 02-3 in the fourth quarter of 2002, primarily due to structured contracts that were reported gross in the current period and net in most of the prior period;
- a $69 million increase from higher competitive retail sales in California by APS Energy Services;
- a $38 million increase from generation sales other than Native Load primarily due to higher prices and sales volumes, including sales from new power plants in service;
- $59 million in lower mark-to-market gains for future-period deliveries primarily as a result of lower market liquidity and lower price volatility; and
- $17 million of lower realized wholesale revenues primarily due to lower unit margins on trading activities that are reported on a net basis.

Real Estate Segment Revenues

Real estate segment revenues were $161 million higher in the year ended December 31, 2003 compared with the prior year primarily as a result of increased asset, land and home sales related to SunCor's effort to accelerate asset sales.

Other Revenues

Other revenues were $24 million higher in the year ended December 31, 2003 compared with the prior year primarily due to our consolidation of NAC's financial statements beginning in the third quarter of 2002, partially offset by decreased sales activity at NAC.

2002 Compared with 2001

Our consolidated net income for the year ended December 31, 2002 was $149 million compared with $312 million for the prior year. We recognized a $66 million after-tax charge in 2002 for the cumulative effect of a change in accounting for trading activities for the early adoption of EITF 02-3 on October 1, 2002 (see Note 18). In 2001, we recognized a $15 million after-tax charge for the cumulative effect of a change in accounting for derivatives, as required by SFAS No. 133 (see Note 18). Net income for 2002 includes income from discontinued operations of $9 million after-tax related to our real estate segment (see Note 22). Excluding the accounting changes and discontinued operations, the $121 million decrease in the period-to-period comparison reflects the following changes in earnings by segment:

- Regulated Electricity Segment – Income from continuing operations increased $18 million primarily due to lower replacement power costs for power plants outages, retail customer growth and higher average customer usage. These positive factors were partially offset by a write-off of Redhawk Units 3 and 4, higher operating costs primarily related to severance costs recorded in 2002, retail electricity price decreases, the effects of milder weather, and higher costs for purchased power and gas due to higher hedged gas and power prices.
- Marketing and Trading Segment – Income from continuing operations decreased $113 million primarily due to lower liquidity and lower price volatility in the wholesale power markets in the western United States.
- Other Segment – Net income decreased approximately $33 million, primarily due to 2002 losses related to our investment in NAC.
- Real Estate Segment – Income from continuing operations increased by $7 million primarily due to increased asset, land and home sales.

Additional details on the major factors that increased (decreased) income from continuing operations and net income for the year ended December 31, 2002 compared with the prior year are contained in the following table (dollars in millions).

	Increase/(Decrease)	
	Pretax	After Tax
Regulated electricity segment gross margin:		
Lower replacement power costs for plant outages due to lower market prices and fewer unplanned outages	$ 127	$ 76
Higher retail sales volumes due to customer growth and higher average usage, excluding weather effects	38	23
2001 charges related to purchased power contracts with Enron and its affiliates	13	8
Retail price reductions effective July 1, 2001 and July 1, 2002	(28)	(17)
Effects of milder weather on retail sales	(27)	(16)
Increased purchased power and fuel costs due to higher hedged gas and power prices, partially offset by improved hedge management, net of mark-to-market reversals	(9)	(5)
Miscellaneous factors, net	(2)	(2)
Net increase in regulated electricity segment gross margin	112	67
Marketing and trading segment gross margin:		
Lower realized wholesale margins net of related mark-to-market reversals due to lower prices and volumes	(91)	(55)
Lower mark-to-market gains for future delivery due to lower market liquidity and lower price volatility	(76)	(45)
Decrease in generation sales other than Native Load due to lower market prices partially offset by higher sales volumes	(66)	(40)
Higher competitive retail sales in California by APS Energy Services	32	19
2001 write-off of prior period mark-to-market value related to trading with Enron and its affiliates	8	5
Lower mark-to-market reversals due to the adoption of EITF 02-3	8	5
Net decrease in marketing and trading segment gross margin	(185)	(111)
Net decrease in regulated electricity and marketing and trading segments' gross margins	(73)	(44)
Lower other gross margin primarily related to NAC losses	(44)	(26)
Higher operations and maintenance expense related to a $47 million write-off of Redhawk Units 3 and 4 and 2002 severance costs of approximately $36 million, partially offset by lower generation reliability costs	(54)	(32)
Higher taxes other than income taxes	(7)	(4)
Lower other income primarily due to a 2001 insurance recovery of environmental remediation costs	(12)	(7)
Higher net interest expense primarily due to higher debt balances and lower capitalized interest	(16)	(10)
Miscellaneous factors, net	4	2
Net decrease in income from continuing operations	$ (202)	(121)
Decrease due to 2002 cumulative effect of change in accounting for trading activities – net of income taxes		(66)
Increase due to 2001 cumulative effect of change in accounting for derivatives – net of income taxes		15
Increase due to 2002 discontinued operations – net of income taxes		9
Net decrease in net income		$ (163)

Regulated Electricity Segment Revenues

Regulated electricity segment revenues related to our regulated retail and wholesale electricity businesses were $94 million lower in the year ended December 31, 2002, compared with the prior year as a result of:

- a $64 million decrease in revenues related to traditional wholesale sales as a result of lower sales volumes and lower prices;
- a $60 million decrease in retail revenues related to milder weather;
- a $69 million increase in retail revenues related to customer growth and higher average usage, excluding weather effects;
- a $28 million decrease in retail revenues related to reductions in retail electricity prices; and
- an $11 million decrease due to other miscellaneous factors.

Marketing and Trading Segment Revenues

Marketing and trading segment revenues were $183 million lower in the year ended December 31, 2002, compared with the prior year as a result of:

- a $96 million decrease in revenues from generation sales other than Native Load primarily due to lower market prices partially offset by higher sales volumes;
- $131 million of lower realized wholesale revenues net of related mark-to-market reversals primarily due to lower prices partially offset by higher volumes;
- a $105 million increase in revenues from higher competitive retail sales in California by APS Energy Services;
- an $8 million increase in revenues due to the absence of a 2001 write-off of prior period mark-to-market value related to trading with Enron and its affiliates;

- $8 million of higher revenues related to the adoption of EITF 02-3; and
- $75 million of lower mark-to-market gains for future delivery primarily as a result of lower market liquidity and lower price volatility, resulting in lower volumes.

Real Estate Segment Revenues

Real Estate segment revenues were $32 million higher in the year ended December 31, 2002 compared with the prior year primarily as a result of increased land, asset and home sales.

Other Revenues

Other revenues were $50 million higher in the year ended December 31, 2002 compared with the prior year primarily due to the consolidation of NAC's financial statements beginning in the third quarter of 2002.

LIQUIDITY AND CAPITAL RESOURCES

Capital Needs and Resources

Capital Expenditure Requirements

The following table summarizes the actual capital expenditures for the year ended December 31, 2003 and estimated capital expenditures for the next three years (dollars in millions):

	Actual	Estimated		
	2003	2004	2005	2006
APS				
Delivery	$ 268	$ 309	$ 390	$ 453
Generation (a)	136	107	160	200
Other	5	10	12	2
Subtotal	429	426	562	655
Pinnacle West Energy (a)(b)	250	61	24	4
SunCor (c)	72	83	27	17
Other (d)	16	11	18	16
Total	$ 767	$ 581	$ 631	692

(a) As discussed in Note 3 under "APS General Rate Case and Retail Rate Adjustment Mechanisms," as part of its 2003 general rate case, APS requested rate base treatment of the PWEC Dedicated Assets. Pinnacle West Energy actual capital expenditures related to PWEC Dedicated Assets were $40 million for 2003 and are estimated to be $15 million in 2004, $21 million in 2005 and $4 million in 2006.

(b) See "Capital Needs and Resources by Company – Pinnacle West Energy" below for further discussion of Pinnacle West Energy's generation construction program. These amounts do not include an expected reimbursement by SNWA of about $100 million (plus capitalized interest), based upon SNWA's agreement to purchase a 25% interest in the Silverhawk project upon completion in 2004.

(c) Consists primarily of capital expenditures for land development and retail and office building construction reflected in "Real estate investments" on the Consolidated Statements of Cash Flows.

(d) Primarily related to the parent company and APS Energy Services.

Delivery capital expenditures are comprised of T&D infrastructure additions and upgrades, capital replacements, new customer construction and related information systems and facility costs. Examples of the types of projects included in the forecast include T&D lines and substations, line extensions to new residential and commercial developments and upgrades to customer information systems. APS completed the Southwest Valley transmission project in 2003 at a cost of approximately $70 million. Major transmission projects are driven by strong regional customer growth. APS will begin major projects each year for the next several years, and expects to spend about $200 million on major transmission projects during the 2004 to 2006 time frame. These amounts are included in "APS-Delivery" in the table above. Completion of these projects will stretch from 2005 through at least 2008.

Generation capital expenditures are comprised of various improvements to APS' existing fossil and nuclear plants and the replacement of Palo Verde steam generators. Examples of the types of projects included in this category are additions, upgrades and capital replacements of various power plant equipment such as turbines, boilers and environmental equipment. Generation also includes nuclear fuel expenditures of approximately $30 million annually for 2004 to 2006.

Replacement of the steam generators in Palo Verde Unit 2 was completed during the fall outage of 2003 at a cost to APS of approximately $70 million. The Palo Verde owners have approved the manufacture of two additional sets of steam generators. These generators will be installed in Unit 1 (scheduled completion in 2005) and Unit 3 (scheduled completion in 2007). Our portion of steam generator expenditures for Units 1 and 3 is approximately $140 million, which will be spent through 2008. In 2004 through 2006, approximately $90 million of the Unit 1 and Unit 3 costs are included in the generation capital expenditures table above and will be funded with internally-generated cash or external financings.

Contractual Obligations

The following table summarizes contractual requirements as of December 31, 2003 (dollars in millions):

	2004	2005-2006	2007-2008	Thereafter	TOTAL
Long-term debt payments, including interest: (a)					
APS	$ 342	$ 699	$ 192	$ 2,567	$ 3,800
Pinnacle West	242	497	–	–	739
SunCor	4	12	5	–	21
El Dorado	1	1	–	–	2
Short-term debt payments, including interest (b)	88	–	–	–	88
Capital lease payments	3	5	2	3	13
Operating lease payments	73	138	132	421	764
Minimum pension funding requirement (c)	100	–	–	–	100
Purchase power and fuel commitments (d)	209	134	102	461	906
Purchase obligations (e)	65	22	5	68	180
Nuclear decommissioning funding requirements	11	22	22	158	213
Total contractual commitments	$ 1,158	$ 1,530	$ 460	$ 3,678	$ 6,826

(a) The long-term debt matures at various dates through fiscal year 2034 and bears interest principally at fixed rates. Interest on variable long-term debt is set at the December 31, 2003 rates. The short-term debt matures within 12 months. The weighted-average interest rate of the short-term debt is 4.26% at December 31, 2003.

(b) The short-term debt matures within 12 months. The weighted-average interest rate of the short-term debt is 4.26% at December 31, 2003.

(c) If currently pending legislation is enacted, our required pension contribution in 2004 would decrease to the $25 to $50 million range. Future pension contributions are not determinable for time periods after 2004.

(d) Our purchase power and fuel commitments include purchases of coal, electricity, natural gas and nuclear fuel (see Note 11).

(e) These contractual obligations include commitments for capital expenditures and other obligations.

Off-Balance Sheet Arrangements

In 2003, we adopted FIN No. 46R, "Consolidation of Variable Interest Entities," as it applies to special-purpose entities. FIN No. 46R requires that we consolidate a VIE if we have a majority of the risk of loss from the VIE's activities or we are entitled to receive a majority of the VIE's residual returns or both. A VIE is a corporation, partnership, trust or any other legal structure that either does not have equity investors with voting rights or has equity investors that do not provide sufficient financial resources for the entity to support its activities. In 1986, APS entered into agreements with three separate SPE lessors in order to sell and lease back interests in Palo Verde Unit 2. The leases are accounted for as operating leases in accordance with GAAP. See Note 9 for further information about the sale leaseback transactions. Based on our assessment of FIN No. 46R, we are not required to consolidate the Palo Verde VIEs. Certain provisions of FIN No. 46R have a future effective date. We do not expect these provisions to have a material impact on our financial statements.

APS is exposed to losses under the Palo Verde sale leaseback agreements upon the occurrence of certain events that APS does not consider to be reasonably likely to occur. Under certain circumstances (for example, the NRC issuing specified violation orders with respect to Palo Verde or the occurrence of specified nuclear events), APS would be required to assume the debt associated with the transactions, make specified payments to the equity participants, and take title to the leased Unit 2 interests, which, if appropriate, may be required to be written down in value. If such an event had occurred as of December 31, 2003, APS would have been required to assume approximately $268 million of debt and pay the equity participants approximately $200 million.

Guarantees and Letters of Credit

We and certain of our subsidiaries have issued guarantees and letters of credit in support of our unregulated businesses. We have also obtained surety bonds on behalf of APS Energy Services. We have not recorded any liability on our Consolidated Balance Sheets with respect to these obligations. See Note 21 for additional information regarding guarantees and letters of credit.

Credit Ratings

The ratings of securities of Pinnacle West and APS as of March 11, 2004 are shown below and are considered to be "investment-grade" ratings. The ratings reflect the respective views of the rating agencies, from which an explanation of the significance of their ratings may be obtained. There is no assurance that these ratings will continue for any given period of time. The ratings may be revised or withdrawn entirely by the rating agencies, if, in their respective judgments, circumstances so warrant. Any downward revision or withdrawal may adversely affect the market price of Pinnacle West's or APS' securities and serve to increase those companies' cost of and access to capital. It may also require additional collateral related to certain derivative instruments (see Note 16).

	Moody's	Standard & Poor's
PINNACLE WEST		
Senior unsecured	Baa2	BBB-
Commercial paper	P-2	A-2
Outlook	Negative	Stable
APS		
Senior secured	A3	A-
Senior unsecured	Baa1	BBB
Secured lease obligation bonds	Baa2	BBB
Commercial paper	P-2	A-2
Outlook	Negative	Stable

Debt Provisions

Pinnacle West's and APS' debt covenants related to their respective financing arrangements include a debt-to-total-capitalization ratio and an interest coverage test. Pinnacle West and APS comply with these covenants and each anticipates it will continue to meet the covenant requirement levels. The ratio of debt to total capitalization cannot exceed 65% for each of the Company and APS individually. At December 31, 2003, the ratio was approximately 54% for Pinnacle West. At December 31, 2003, the ratio was approximately 53% for APS. The provisions regarding interest coverage require a minimum cash coverage of two times the interest requirements for each of the Company and APS. Based on 2003 results, the coverages were approximately 4 times for the Company, 4 times for the APS bank financing agreements and 15 times for the APS mortgage indenture. Failure to comply with such covenant levels would result in an event of default which, generally speaking, would require the immediate repayment of the debt subject to the covenants.

Neither Pinnacle West's nor APS' financing agreements contain "ratings triggers" that would result in an acceleration of the required interest and principal payments in the event of a ratings downgrade. However, in the event of a ratings downgrade, Pinnacle West and/or APS may be subject to increased interest costs under certain financing agreements.

- All of Pinnacle West's bank agreements contain "cross-default" provisions that would result in defaults and the potential acceleration of payment under these loan agreements if Pinnacle West or APS were to default under other agreements. All of APS' bank agreements contain cross-default provisions that would result in defaults and the potential acceleration of payment under these bank agreements if APS were to default under other agreements. Pinnacle West's and APS' credit agreements generally contain provisions under which the lenders could refuse to advance loans in the event of a material adverse change in financial condition or financial prospects.

Capital Needs and Resources by Company

Pinnacle West (Parent Company)

Our primary cash needs are for dividends to our shareholders; interest payments and optional and mandatory repayments of principal on our long-term debt (see the table above for our contractual requirements, including our debt repayment obligations, but excluding optional repayments) and equity infusions into our subsidiaries, primarily Pinnacle West Energy. On October 22, 2003, our board of directors increased the common stock dividend to an indicated annual rate of $1.80 per share from $1.70 per share, effective with the December 1, 2003 dividend payment. The level of our common dividends and future dividend growth will be dependent on a number of factors including, but not limited to, payout ratio trends, free cash flow and financial market conditions.

Our primary sources of cash are dividends from APS, external financings and cash distributions from our other subsidiaries, primarily SunCor. For the years 2001 through 2003, total dividends from APS were $510 million and total distributions from SunCor were $121 million. For the year ended December 31, 2003, dividends from APS were approximately $170 million and distributions from SunCor were approximately $108 million. We expect SunCor to make cash distributions to the parent company of $80 to $100 million annually in 2004 and 2005 due to anticipated accelerated asset sales activity. As discussed in Note 3 under "ACC Financing Orders," APS must maintain a common equity ratio of at least 40% and may not pay common dividends if the payment would reduce its common equity below that threshold. As defined in the Financing Order, common equity ratio is common equity divided by common equity plus long-term debt, including current maturities of long-term debt. At December 31, 2003, APS' common equity ratio was approximately 46%.

On May 12, 2003, APS issued $500 million of debt as follows: $300 million aggregate principal amount of its 4.65% Notes due 2015 and $200 million aggregate principal amount of its 5.625% Notes due 2033. Also on May 12, 2003, APS made a $500 million loan to Pinnacle West Energy, and Pinnacle West Energy distributed the net proceeds of that loan to us to fund our repayment of a portion of the debt incurred to finance the construction of the PWEC Dedicated Assets. See "ACC Financing Order" in Note 3 for additional information. With Pinnacle West Energy's distribution to us on May 12, 2003, we repaid the outstanding balance ($167 million) under a credit facility. We used a portion of the remaining proceeds to redeem our $250 million Floating Rate Notes due 2003 on June 2, 2003 and to repay other short-term debt. On November 12, 2003, we issued $165 million of our Floating Rate Senior Notes due 2005.

At December 31, 2003, the parent company's outstanding long-term debt, including current maturities, was $681 million. At December 31, 2003, we had unused credit commitments from various banks totaling $275 million, which were available to support the issuance of commercial paper or to be used as bank borrowings. At December 31, 2003, we had no commercial paper outstanding and no short-term borrowings. We ended 2003 in an invested position.

Pinnacle West sponsors a pension plan that covers employees of Pinnacle West and our subsidiaries. We contribute at least the minimum amount required under IRS regulations, but no more than the maximum tax-deductible amount. The minimum required funding takes into consideration the value of the fund assets and our pension obligation. We elected to contribute cash to our pension plan in each of the last five years; our minimum required contributions during each of those years was zero. Specifically, we contributed $73 million for 2002 ($46 million of which was contributed in June 2003); $24 million for 2001; $44 million for 2000 ($20 million of

which was contributed in 2001); and $25 million for 1999. APS and other subsidiaries fund their share of the pension contribution, of which APS represents approximately 89% of the total funding amounts described above. The assets in the plan are mostly domestic common stocks, bonds and real estate. Future year contribution amounts are dependent on fund performance and fund valuation assumptions. Under current law, we are required to contribute approximately $100 million to our pension plans in 2004 and expect to contribute approximately $50 million to our other postretirement benefit plan in 2004. If currently pending legislation is enacted, our required pension contribution in 2004 would decrease to the $25 to $50 million range.

APS

APS' capital requirements consist primarily of capital expenditures and optional and mandatory redemptions of long-term debt. See "Pinnacle West (Parent Company)" above and Note 3 for discussion of the $500 million financing arrangement between APS and Pinnacle West Energy approved by the ACC in 2003 and discussion of a $125 million financing arrangement between APS and Pinnacle West.

APS pays for its capital requirements with cash from operations and, to the extent necessary, external financings. APS has historically paid for its dividends to Pinnacle West with cash from operations. See "Pinnacle West (Parent Company)" above for a discussion of common equity ratio that APS must maintain in order to pay dividends to Pinnacle West.

On April 7, 2003, APS redeemed approximately $33 million of its First Mortgage Bonds, 8% Series due 2025, and on August 1, 2003, APS redeemed approximately $54 million of its First Mortgage Bonds, 7.25% Series due 2023.

On February 15, 2004, $125 million of APS 5.875% Notes due 2004 were redeemed at maturity and on March 1, 2004, $30 million of APS' First Mortgage Bonds, 6.625% Series due 2004 were redeemed at maturity. APS used cash from operations and short-term debt to redeem the maturing debt.

APS' outstanding debt was approximately $2.6 billion at December 31, 2003. At December 31, 2003, APS had unused credit commitments from various banks totaling about $250 million, which were available either to support the issuance of commercial paper or to be used as bank borrowings. At December 31, 2003, APS had no outstanding commercial paper or bank borrowings. APS ended 2003 in an invested position.

Although provisions in APS' first mortgage bond indenture, articles of incorporation and ACC financing orders establish maximum amounts of additional first mortgage bonds, debt and preferred stock that APS may issue, APS does not expect any of these provisions to limit its ability to meet its capital requirements.

Pinnacle West Energy

The costs of Pinnacle West Energy's construction of 2,360 MW of generating capacity from 2000 through 2004 are expected to be about $1.4 billion, of which $1.35 billion has been incurred through December 31, 2003. This does not reflect the proceeds from an anticipated sale in 2004 to SNWA of a 25% interest in the 570 MW Silverhawk Combined Cycle Plant 20 miles north of Las Vegas, Nevada, which would equal about $100 million (plus capitalized interest) of Pinnacle West Energy's cumulative capital expenditures in the project. SNWA has agreed to purchase a 25% interest in the project upon completion. Such purchase is subject to an appropriation of funds by SNWA. Pinnacle West Energy's capital requirements are currently funded through capital infusions from Pinnacle West, which finances these infusions through debt and equity financings and internally-generated cash. See the capital expenditures table above for actual capital expenditures in 2003 and projected capital expenditures for the next three years.

See Note 3 and "Pinnacle West (Parent Company)" above for a discussion of the $500 million financing arrangement between APS and Pinnacle West Energy authorized by the ACC pursuant to the Financing Order.

Other Subsidiaries

During the past three years, SunCor funded its cash requirements with cash from operations and its own external financings. SunCor's capital needs consist primarily of capital expenditures for land development and retail and office building construction. See the capital expenditures table above for actual capital expenditures in 2003 and projected capital expenditures for the next three years. SunCor expects to fund its capital requirements with cash from operations and external financings.

In 2003, SunCor acquired or issued $10 million in long-term debt, and redeemed, refinanced or repaid $1 million in long-term debt (see Note 6).

SunCor's outstanding long and short-term debt was approximately $104 million as of December 31, 2003. SunCor's total short-term debt was $86 million at December 31, 2003. SunCor had a $120 million line of credit, under which $50 million of short-term borrowings were outstanding at December 31, 2003. SunCor's long-term debt, including current maturities, totaled $18 million at December 31, 2003.

We expect SunCor to make cash distributions to the parent company of $80 to $100 million annually in 2004 and 2005 due to anticipated accelerated asset sales activity.

El Dorado funded its cash requirements during the past three years, primarily for NAC in 2002, with cash infused by the parent company and with cash from operations. El Dorado expects minimal capital requirements over the next three years and intends to focus on prudently realizing the value of its existing investments.

APS Energy Services' cash requirements during the past three years were funded with cash infusions from the parent company and with cash from operations. See the capital expenditures table above regarding APS Energy Services' actual capital expenditures for 2003 and projected capital expenditures for the next three years.

CRITICAL ACCOUNTING POLICIES

In preparing the financial statements in accordance with GAAP, management must often make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and related disclosures at the date of the financial statements and during the reporting period. Some of those judgments can be subjective and complex, and actual results could differ from those estimates. We consider the following accounting policies to be our most critical because of the uncertainties, judgments and complexities of the underlying accounting standards and operations involved.

Regulatory Accounting

Regulatory accounting allows for the actions of regulators, such as the ACC and the FERC, to be reflected in our financial statements. Their actions may cause us to capitalize costs that would otherwise be included as an expense in the current period by unregulated companies. If future recovery of costs ceases to be probable, the assets would be written off as a charge in current period earnings. We had $165 million of regulatory assets on the Consolidated Balance Sheets at December 31, 2003. See Notes 1 and 3 for more information about regulatory assets and APS' general rate case.

Pensions and Other Postretirement Benefit Accounting

Changes in our actuarial assumptions used in calculating our pension and other postretirement benefit liability and expense can have a significant impact on our earnings and financial position. The most relevant actuarial assumptions are the discount rate used to measure our liability and net periodic cost, the expected long-term rate of return on plan assets used to estimate earnings on invested funds over the long-term, and the assumed healthcare cost trend rates. We review these assumptions on an annual basis and adjust them as necessary.

The following chart reflects the sensitivities that a change in certain actuarial assumptions would have had on the 2003 projected benefit obligation, our 2003 reported pension liability on the Consolidated Balance Sheets and our 2003 reported pension expense, after consideration of amounts capitalized or billed to electric plant participants, on our Consolidated Statements of Income (dollars in millions):

	Increase/(Decrease)		
Actuarial Assumption (a)	Impact on Projected Benefit Obligation	Impact on Pension Liability	Impact on Pension Expense
Discount rate:			
Increase 1%	$ (165)	$ (123)	$ (6)
Decrease 1%	189	139	6
Expected long-term rate of return on plan assets:			
Increase 1%	–	–	(3)
Decrease 1%	–	–	3

(a) Each fluctuation assumes that the other assumptions of the calculation are held constant.

The following chart reflects the sensitivities that a change in certain actuarial assumptions would have had on the 2003 accumulated other postretirement benefit obligation and our 2003 reported other postretirement benefit expense, after consideration of amounts capitalized or billed to electric plant participants, on our Consolidated Statements of Income (dollars in millions):

	Increase/(Decrease)	
Actuarial Assumption (a)	Impact on Accumulated Postretirement Benefit Obligation	Impact on Other Postretirement Benefit Expense
Discount rate:		
Increase 1%	$ (81)	$ (5)
Decrease 1%	96	5
Health care cost trend rate (b):		
Increase 1%	95	7
Decrease 1%	(76)	(5)
Expected long-term rate of return on plan assets – pretax:		
Increase 1%	–	(1)
Decrease 1%	–	1

(a) Each fluctuation assumes that the other assumptions of the calculation are held constant.
(b) This assumes a 1% change in the initial and ultimate health care cost trend rate.

See Note 8 for further details about our pension and other postretirement benefit plans.

Derivative Accounting

Derivative accounting requires evaluation of rules that are complex and subject to varying interpretations. Our evaluation of these rules, as they apply to our contracts, will determine whether we use accrual accounting or fair value (mark-to-market) accounting. Mark-to-market accounting requires that changes in fair value be recorded in earnings or, if certain hedge accounting criteria are met, in common stock equity (as a component of other comprehensive income (loss)). See "Market Risks – Commodity Price Risk" below for quantitative analysis. See Note 18 for a further discussion on derivative and energy trading accounting.

Mark-to-Market Accounting

The market value of our derivative contracts is not always readily determinable. In some cases, we use models and other valuation

techniques to determine fair value. The use of these models and valuation techniques sometimes requires subjective and complex judgment. Actual results could differ from the results estimated through application of these methods. Our marketing and trading portfolio consists of structured activities hedged with a portfolio of forward purchases that protects the economic value of the sales transactions. See "Market Risks – Commodity Price Risk" below for quantitative analysis. See Note 1 for discussion on accounting policies and Note 18 for a further discussion on derivative and energy trading accounting.

OTHER ACCOUNTING MATTERS

Accounting for Derivative and Trading Activities

We adopted EITF 03-11 effective October 1, 2003. EITF 03-11 provides guidance on whether realized gains and losses on physically settled derivative contracts not held for trading purposes should be reported on a net or gross basis and concluded such classification is a matter of judgment that depends on the relevant facts and circumstances. In the electricity business, some contracts to purchase energy are netted against other contracts to sell energy. This is called "book-out" and usually occurs in contracts that have the same terms (quantities and delivery points) and for which power does not flow. We netted these book-outs reducing both revenues and purchased power and fuel costs in 2003, 2002 and 2001, but this did not impact our financial condition, net income or cash flows.

We adopted EITF 02-3 in the fourth quarter of 2002. We recorded a $66 million after-tax charge in net income as a cumulative effect adjustment for the previously recorded accumulated unrealized mark-to-market on energy trading contracts that did not meet the accounting definition of a derivative. Our energy trading contracts that are derivatives are accounted for at fair value under SFAS No. 133. Contracts that do not meet the definition of a derivative are now accounted for on an accrual basis with the associated revenues and costs recorded at the time the contracted commodities are delivered or received.

In 2001, we adopted SFAS No. 133 and recorded a $15 million after-tax charge in net income and a $72 million after-tax credit in common stock equity (as a component of other comprehensive income), both as a cumulative effect of a change in accounting for derivatives.

See Notes 1 and 18 for further information on accounting for derivatives.

Asset Retirement Obligations

On January 1, 2003, we adopted SFAS No. 143, "Accounting for Asset Retirement Obligations." The standard requires the fair value of asset retirement obligations to be recorded as a liability, along with an offsetting plant asset, when the obligation is incurred. Accretion of the liability due to the passage of time is an operating expense and the capitalized cost is depreciated over the useful life of the long-lived asset. (See Note 1 for more information regarding our previous accounting for removal costs.)

We determined that we have asset retirement obligations for our nuclear facilities (nuclear decommissioning) and certain other generation, transmission and distribution assets. On January 1, 2003, we recorded a liability of $219 million for our asset retirement obligations including the accretion impacts; a $67 million increase in the carrying amount of the associated assets; and a net reduction of $192 million in accumulated depreciation related primarily to the reversal of previously recorded accumulated decommissioning and other removal costs related to these obligations. Additionally, we recorded a regulatory liability of $40 million for our asset retirement obligations related to our regulated utility. This regulatory liability represents the difference between the amount currently being recovered in regulated rates and the amount calculated under SFAS No. 143. We believe we can recover in regulated rates the transition costs and ongoing current period costs calculated in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation" (see Note 1) and SFAS No. 143 (see Note 12). Adopting SFAS No. 143 had no impact on our Consolidated Statements of Income or our Consolidated Statements of Cash Flow.

Variable Interest Entities

See "Liquidity and Capital Resources – Off-Balance Sheet Arrangements" and Note 20 for discussion of VIEs.

FACTORS AFFECTING OUR FINANCIAL OUTLOOK

APS General Rate Case

We believe APS' general rate case pending before the ACC is the key issue affecting our outlook. As discussed in greater detail in Note 3, in this rate case APS has requested, among other things, a 9.8% retail rate increase (approximately $175 million annually), rate treatment for the PWEC Dedicated Assets and the recovery of $234 million written off by APS as part of the 1999 Settlement Agreement. In its filed testimony, the ACC staff recommended, among other things, that the ACC decrease APS' rates by approximately 8% (approximately $143 million annually), not allow the PWEC Dedicated Assets to be included in APS' rate base, and not allow APS to recover any of the $234 million written off as a result of the 1999 Settlement Agreement. The ACC staff recommendations, if implemented as proposed, could have a material adverse impact on our results of operations, financial position, liquidity, dividend sustainability, credit ratings and access to capital markets. We believe that APS' rate case requests are supported by, among other things, APS' demonstrated need for the PWEC Dedicated Assets; APS' need to attract capital at reasonable rates of return to support the required capital investment to ensure continued customer reliability in APS' high-growth service territory; and the conditions in the western energy market. As a result, we believe it is unlikely that the ACC would adopt the ACC staff recommendations in their present form, although we can give no assurances in that

regard. The hearing on the rate case is scheduled to begin on May 25, 2004. We believe the ACC will be able to make a decision by the end of 2004.

Wholesale Power Market Conditions

The marketing and trading division focuses primarily on managing APS' purchased power and fuel risks in connection with its costs of serving retail customer demand. We moved this division to APS in early 2003 for future marketing and trading activities (existing wholesale contracts remained at Pinnacle West) as a result of the ACC's Track A Order prohibiting APS' transfer of generating assets to Pinnacle West Energy. Additionally, the marketing and trading division, subject to specified parameters, markets, hedges and trades in electricity, fuels and emission allowances and credits. Our future earnings will be affected by the strength or weakness of the wholesale power market. The market has suffered a substantial reduction in overall liquidity because there are fewer creditworthy counterparties and because several key participants have exited the market or scaled back their activities. Based on the erosion in the market and on the market outlook, we currently expect contributions from our trading activities to be negligible for 2004, and approximately $10 million (pretax) annually thereafter.

Generation Construction Program

See "Liquidity and Capital Resources – Pinnacle West Energy" for information regarding Pinnacle West Energy's generation construction program, which is nearing completion. The additional generation is expected to increase revenues, fuel expenses, operating expenses and financing costs.

Factors Affecting Operating Revenues

General Electric operating revenues are derived from sales of electricity in regulated retail markets in Arizona and from competitive retail and wholesale power markets in the western United States. These revenues are expected to be affected by electricity sales volumes related to customer mix, customer growth and average usage per customer as well as electricity prices and variations in weather from period to period. Competitive sales of energy and energy-related products and services are made by APS Energy Services in western states that have opened to competitive supply.

Customer Growth Customer growth in APS' service territory averaged about 3.4% a year for the three years 2001 through 2003; we currently expect customer growth to average about 3.5% per year from 2004 to 2006. We currently estimate that total retail electricity sales in kilowatt-hours will grow 4.9% on average, from 2004 through 2006, before the retail effects of weather variations. The customer and sales growth referred to in this paragraph applies to Native Load customers. Customer growth for the year ended December 31, 2003 compared with the prior year period was 3.3%.

Retail Rate Changes As part of the 1999 Settlement Agreement, APS agreed to a series of annual retail electricity price reductions of 1.5% on July 1 for each of the years 1999 to 2003 for a total of 7.5%. The final price reduction was implemented July 1, 2003. See "1999 Settlement Agreement" in Note 3 for further information. In addition, the Company has requested a 9.8% retail rate increase to be effective July 1, 2004. See "APS General Rate Case and Retail Rate Adjustment Mechanisms" in Note 3 for further information.

Other Factors Affecting Future Financial Results

Purchased Power and Fuel Costs Purchased power and fuel costs are impacted by our electricity sales volumes, existing contracts for purchased power and generation fuel, our power plant performance, prevailing market prices, new generating plants being placed in service and our hedging program for managing such costs. See "Natural Gas Supply" in Note 11 for more information on fuel costs.

Operations and Maintenance Expenses Operations and maintenance expenses are impacted by growth, power plant additions and operations, inflation, outages, higher trending pension and other postretirement benefit costs and other factors.

Depreciation and Amortization Expenses Depreciation and amortization expenses are impacted by net additions to existing utility plant and other property, changes in regulatory asset amortization and our generation construction program. West Phoenix Unit 4 was placed in service in June 2001. Redhawk Units 1 and 2 and the new Saguaro Unit 3 began commercial operations in July 2002. West Phoenix Unit 5 was placed in service in July 2003 and Silverhawk is expected to be in service in mid-2004. The regulatory assets to be recovered under the 1999 Settlement Agreement are currently being amortized as follows (dollars in millions):

1999	2000	2001	2002	2003	2004	TOTAL
$164	$158	$145	$115	$86	$18	$686

Property Taxes Taxes other than income taxes consist primarily of property taxes, which are affected by tax rates and the value of property in-service and under construction. The average property tax rate for APS, which currently owns the majority of our property, was 9.3% of assessed value for 2003 and 9.7% for 2002. We expect property taxes to increase primarily due to our generation construction program, as the plants phase-in to the property tax base over a five-year period, and our additions to existing facilities.

Interest Expense Interest expense is affected by the amount of debt outstanding and the interest rates on that debt. The primary factors affecting borrowing levels in the next several years are expected to be our capital requirements and our internally generated cash flow. Capitalized interest offsets a portion of interest expense while capital projects are under construction. We stop accruing capitalized interest on a project when it is placed in commercial

operation. As noted above, we placed new power plants in commercial operation in 2001, 2002 and 2003 and we expect to bring an additional plant on-line in 2004. Interest expense is also affected by interest rates on variable-rate debt and interest rates on the refinancing of the Company's future liquidity needs. In addition, see Note 1 for a discussion of AFUDC.

Retail Competition The regulatory developments and legal challenges to the Rules discussed in Note 3 have raised considerable uncertainty about the status and pace of retail electric competition and of electric restructuring in Arizona. Although some very limited retail competition existed in APS' service area in 1999 and 2000, there are currently no active retail competitors providing unbundled energy or other utility services to APS' customers. As a result, we cannot predict when, and the extent to which, additional competitors will re-enter APS' service territory.

Subsidiaries In the case of SunCor, efforts to accelerate asset sales activities in 2003 were successful. A portion of these sales have been, and additional amounts may be required to be, reported as discontinued operations on our Consolidated Statements of Income. The annual earnings contribution from SunCor was $56 million after tax in 2003. See Note 22 for further discussion. We anticipate SunCor's annual earnings contributions in 2004 and 2005 will be in the $30 to $40 million range after tax.

The annual earnings contribution from APS Energy Services is expected to be positive over the next several years due primarily to a number of retail electricity contracts in California. APS Energy Services had after tax earnings of $16 million in 2003.

We expect SunCor and APS Energy Services to have combined earnings of approximately $10 million per year after tax beyond 2005.

El Dorado's historical results are not necessarily indicative of future performance for El Dorado. In addition, we do not currently expect material losses related to NAC in the future.

General Our financial results may be affected by a number of broad factors. See "Forward-Looking Statements" below for further information on such factors, which may cause our actual future results to differ from those we currently seek or anticipate.

Market Risks

Our operations include managing market risks related to changes in interest rates, commodity prices and investments held by the nuclear decommissioning trust fund and our pension plans.

Interest Rate and Equity Risk

Our major financial market risk exposure is changing interest rates. Changing interest rates will affect interest paid on variable-rate debt and interest earned by our nuclear decommissioning trust fund (see Note 12). Our policy is to manage interest rates through the use of a combination of fixed-rate and floating-rate debt. On January 29, 2004, we entered into a fixed-for-floating interest rate swap transaction (see Note 6 for additional information). The nuclear decommissioning fund also has risk associated with changing market values of equity investments. Nuclear decommissioning costs are recovered in regulated electricity prices.

The table below presents contractual balances of our consolidated long-term and short-term debt at the expected maturity dates as well as the fair value of those instruments on December 31, 2003. The interest rates presented in the tables below represent the weighted-average interest rates for the year ended December 31, 2003 (dollars in thousands):

	Short-Term Debt		Variable-Rate Long-Term Debt		Fixed-Rate Long-Term Debt	
December 31, 2003	Interest Rates	Amount	Interest Rates	Amount	Interest Rates	Amount
2004	4.26%	$ 86,081	2.68%	$ 1,209	5.33%	$ 424,271
2005	–	–	1.99%	166,269	7.27%	403,204
2006	–	–	6.55%	2,937	6.49%	391,585
2007	–	–	4.99%	373	5.54%	1,256
2008	–	–	5.19%	5,269	5.55%	1,098
Years thereafter	–	–	1.51%	386,860	5.83%	1,547,775
Total		$ 86,081		$ 562,917		$ 2,769,189
Fair Value		$ 86,081		$ 563,047		$ 2,913,190

Commodity Price Risk

We are exposed to the impact of market fluctuations in the commodity price and transportation costs of electricity, natural gas, coal and emissions allowances. We manage risks associated with these market fluctuations by utilizing various commodity instruments that qualify as derivatives, including exchange-traded futures and options and over-the-counter forwards, options and swaps. Our ERMC, consisting of officers and key management personnel, oversees company-wide energy risk management activities and monitors the results of marketing and trading

activities to ensure compliance with our stated energy risk management and trading policies. As part of our risk management program, we use such instruments to hedge purchases and sales of electricity, fuels and emissions allowances and credits. The changes in market value of such contracts have a high correlation to price changes in the hedged commodities. In addition, subject to specified risk parameters monitored by the ERMC, we engage in marketing and trading activities intended to profit from market price movements.

The mark-to-market value of derivative instruments related to our risk management and trading activities are presented in two categories consistent with our business segments:

- Regulated Electricity – non-trading derivative instruments that hedge our purchases and sales of electricity and fuel for APS' Native Load requirements of our regulated electricity business segment; and
- Marketing and Trading – non-trading and trading derivative instruments of our competitive business segment.

The following tables show the pretax changes in mark-to-market of our non-trading and trading derivative positions in 2003 and 2002 (dollars in millions):

	Regulated Electricity	Marketing and Trading
Mark-to-market of net positions at December 31, 2002	$ (49)	$ 57
Change in mark-to-market losses for future period deliveries	(5)	(7)
Changes in cash flow hedges recorded in OCI	41	44
Ineffective portion of changes in fair value recorded in earnings	8	–
Mark-to-market losses/(gains) realized during the year	5	(25)
Mark-to-market of net positions at December 31, 2003	$ –	$ 69

	Regulated Electricity	Marketing and Trading
Mark-to-market of net positions at December 31, 2001	$ (107)	$ 138
Cumulative effect adjustment due to adoption of EITF 02-3	–	(109)
Change in mark-to-market (losses)/gains for future period deliveries	(13)	52
Changes in cash flow hedges recorded in OCI	57	16
Ineffective portion of changes in fair value recorded in earnings	11	–
Mark-to-market losses/(gains) realized during the year	3	(43)
Change in valuation techniques	–	3
Mark-to-market of net positions at December 31, 2002	$ (49)	$ 57

The tables below show the fair value of maturities of our non-trading and trading derivative contracts (dollars in millions) at December 31, 2003 by maturities and by the type of valuation that is performed to calculate the fair values. See Note 1, "Mark-to-Market Accounting," for more discussion on our valuation methods.

Regulated Electricity

Source of Fair Value	2004	2005	Years Thereafter	Total Fair Value
Prices actively quoted	$ (4)	$ 3	$ –	$ (1)
Prices provided by other external sources	2	–	–	2
Prices based on models and other valuation methods	(1)	–	–	(1)
Total by maturity	$ (3)	$ 3	$ –	$ –

Marketing and Trading

Source of Fair Value	2004	2005	2006	2007	2008	Years Thereafter	Total Fair Value
Prices actively quoted	$ (18)	$ –	$ –	$ 10	$ 10	$ –	$ 2
Prices provided by other external sources	22	23	25	20	8	(2)	96
Prices based on models and other valuation methods	12	(7)	(13)	(14)	(6)	(1)	(29)
Total by maturity	$ 16	$ 16	$ 12	$ 16	$ 12	$ (3)	$ 69

The table below shows the impact that hypothetical price movements of 10% would have on the market value of our risk management and trading assets and liabilities included on the Consolidated Balance Sheets at December 31, 2003 (dollars in millions).

	Gain (Loss)	
Commodity	Price Up 10%	Price Down 10%
Mark-to-market changes reported in earnings (a):		
Electricity	$ (2)	$ 2
Natural gas	(1)	1
Other	1	–
Mark-to-market changes reported in OCI (b):		
Electricity	36	(36)
Natural gas	30	(30)
Total	$ 64	$ (63)

(a) These contracts are primarily structured sales activities hedged with a portfolio of forward purchases that protects the economic value of the sales transactions.
(b) These contracts are hedges of our forecasted purchases of natural gas and electricity. The impact of these hypothetical price movements would substantially offset the impact that these same price movements would have on the physical exposures being hedged.

Credit Risk

We are exposed to losses in the event of nonperformance or nonpayment by counterparties. We have risk management and trading contracts with many counterparties, including two counterparties for which a worst case exposure represents approximately 37% of our $237 million of risk management and trading assets as of December 31, 2003. See Note 1, "Mark-to-Market Accounting" for a discussion of our credit valuation adjustment policy. See Note 18 for further discussion of credit risk.

Forward-Looking Statements

This document contains forward-looking statements based on current expectations, and we assume no obligation to update these statements or make any further statements on any of these issues, except as required by applicable law. These forward-looking statements are often identified by words such as "predict," "hope," "may," "believe," "anticipate," "plan," "expect," "require," "intend," "assume" and similar words. Because actual results may differ materially from expectations, we caution readers not to place undue reliance on these statements. A number of factors could cause future results to differ materially from historical results, or from results or outcomes currently expected or sought by us. These factors include, but are not limited to:

- state and federal regulatory and legislative decisions and actions, including the outcome of the rate case APS filed with the ACC on June 27, 2003 and the wholesale electric price mitigation plan adopted by the FERC;
- the outcome of regulatory, legislative and judicial proceedings relating to the restructuring;
- the ongoing restructuring of the electric industry, including the introduction of retail electric competition in Arizona and decisions impacting wholesale competition;
- market prices for electricity and natural gas;
- power plant performance and outages;
- weather variations affecting local and regional customer energy usage;
- energy usage;
- regional economic and market conditions, including the results of litigation and other proceedings resulting from the California energy situation, volatile purchased power and fuel costs and the completion of generation and transmission construction in the region, which could affect customer growth and the cost of power supplies;
- the cost of debt and equity capital and access to capital markets;
- our ability to compete successfully outside traditional regulated markets (including the wholesale market);
- the performance of our marketing and trading activities due to volatile market liquidity and deteriorating counterparty credit and the use of derivative contracts in our business (including the interpretation of the subjective and complex accounting rules related to these contracts);
- changes in accounting principles generally accepted in the United States of America;
- the successful completion of our generation construction program;
- regulatory issues associated with generation construction, such as permitting and licensing;
- the performance of the stock market and the changing interest rate environment, which affect the amount of our required contributions to our pension plan and nuclear decommissioning trust funds, as well as our reported costs of providing pension and other postretirement benefits;
- technological developments in the electric industry;
- the strength of the real estate market in SunCor's market areas, which include Arizona, Idaho, New Mexico and Utah;
- conservation programs; and
- other uncertainties, all of which are difficult to predict and many of which are beyond our control.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management at Pinnacle West has always understood and accepted responsibility for our financial statements and related disclosures and the effectiveness of internal control over financial reporting ("internal control"). Just as we do throughout all aspects of our business, we continuously strive to identify opportunities to enhance the effectiveness and efficiency of internal control.

SEC rules implementing Section 404 of the Sarbanes-Oxley Act will require our 2004 Annual Report to contain a management's report and an independent accountants' report regarding the effectiveness of internal control. However, in this 2003 Annual Report, we chose to voluntarily include this report on internal control. As a basis for our report, we tested and evaluated the design, documentation and operating effectiveness of internal control.

In early March 2004, the PCAOB issued its auditing standard, which may require changes to the processes we utilize to test and evaluate the design, documentation and operating effectiveness of internal control and may affect our future internal control disclosures. Based on our assessment as of December 31, 2003, we make the following assertion:

- Management is responsible for establishing and maintaining effective internal control over financial reporting of Pinnacle West Capital Corporation and Subsidiaries (the "Company"). The internal control contains monitoring mechanisms, and actions are taken to correct deficiencies identified.
- There are inherent limitations in the effectiveness of any internal control, including the possibility of human error and the circumvention or overriding of controls. Accordingly, even effective internal controls can provide only reasonable assurance with respect to financial statement preparation. Further, because of changes in conditions, the effectiveness of internal control may vary over time.
- Management evaluated the Company's internal control over financial reporting as of December 31, 2003. This assessment was based on criteria for effective internal control over financial reporting described in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management believes that the Company maintained effective internal control over financial reporting as of December 31, 2003.

March 11, 2004

INDEPENDENT ACCOUNTANTS' REPORT

Board of Directors and Stockholders
Pinnacle West Capital Corporation
Phoenix, Arizona

We have examined the accompanying management's assertion that Pinnacle West Capital Corporation and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2003, based on the criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting. Our responsibility is to express an opinion on management's assertion based on our examination.

Our examination was conducted in accordance with attestation standards established by the American Institute of Certified Public Accountants ("AICPA") and, accordingly, included obtaining an understanding of the internal control over financial reporting, testing and evaluating the design and operating effectiveness of the internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our examination provides a reasonable basis for our opinion.

Because of inherent limitations in any internal control, misstatements due to error or fraud may occur and not be detected. Also, projections of any evaluation of the internal control over financial reporting to future periods are subject to the risk that the internal control may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assertion that the Company maintained effective internal control over financial reporting as of December 31, 2003 is fairly stated, in all material respects, based on criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

An examination of management's assertion regarding the effectiveness of internal control under AICPA standards may not be the same in scope as an audit of internal control under the current proposed standards of the Public Company Accounting Oversight Board (the "PCAOB") and, accordingly, may not necessarily result in the same conclusion or disclose all matters in internal control that might ultimately be noted in performing an audit under PCAOB standards when they are finally adopted. Accordingly, our examination of the accompanying Management's Report on Internal Control Over Financial Reporting is not intended to comply with, and should not be relied upon for compliance with, the U.S. Securities and Exchange Commission rule relating to Section 404 or Section 103 of the Sarbanes-Oxley Act of 2002.

Deloitte & Touche LLP

DELOITTE & TOUCHE LLP
Phoenix, Arizona
March 11, 2004

INDEPENDENT AUDITORS' REPORT

Board of Directors and Stockholders
Pinnacle West Capital Corporation
Phoenix, Arizona

We have audited the accompanying consolidated balance sheets of Pinnacle West Capital Corporation and subsidiaries (the "Company") as of December 31, 2003 and 2002, and the related consolidated statements of income, changes in common stock equity and cash flows for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Pinnacle West Capital Corporation and subsidiaries at December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 18 to the consolidated financial statements, in 2003 the Company changed its method of accounting for non-trading derivatives in order to comply with the provisions of Emerging Issues Task Force Issue No. 03-11, *Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not "Held for Trading Purposes" as Defined in Issue No. 02-3.*

As discussed in Note 18 to the consolidated financial statements, in 2002 the Company changed its method of accounting for trading activities in order to comply with the provisions of Emerging Issues Task Force Issue No. 02-3, *Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities.*

As discussed in Note 18 to the consolidated financial statements, in 2001 the Company changed its method of accounting for derivatives and hedging activities in order to comply with the provisions of Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities.*

Deloitte & Touche LLP

DELOITTE & TOUCHE LLP
Phoenix, Arizona
March 11, 2004

CONSOLIDATED STATEMENTS OF INCOME (dollars and shares in thousands, except per share amounts)

Year Ended December 31,	2003	2002	2001
OPERATING REVENUES			
Regulated electricity segment	$ 1,976,075	$ 1,890,391	$ 1,964,305
Marketing and trading segment	391,886	266,879	469,784
Real estate segment	361,604	201,081	168,908
Other revenues	86,287	61,937	11,771
Total	2,817,852	2,440,288	2,634,768
OPERATING EXPENSES			
Regulated electricity segment purchased power and fuel	517,320	376,911	583,080
Marketing and trading segment purchased power and fuel	344,862	154,987	152,762
Operations and maintenance	548,732	584,538	530,095
Real estate operations segment	305,974	185,925	153,462
Depreciation and amortization	438,143	424,082	427,903
Taxes other than income taxes	110,270	107,952	101,068
Other expenses	70,498	104,959	10,375
Total	2,335,799	1,939,354	1,958,745
OPERATING INCOME	482,053	500,934	676,023
OTHER			
Allowance for equity funds used during construction	14,240	–	–
Other income	35,563	14,910	26,416
Other expenses	(20,574)	(33,655)	(33,577)
Total	29,229	(18,745)	(7,161)
INTEREST EXPENSE			
Interest charges	204,590	187,512	175,822
Capitalized interest	(29,444)	(43,749)	(47,862)
Total	175,146	143,763	127,960
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	336,136	338,426	540,902
INCOME TAXES	105,560	132,228	213,535
INCOME FROM CONTINUING OPERATIONS	230,576	206,198	327,367
Income from discontinued operations – net of income taxes of $6,529 and $5,872	10,003	6,955	–
Cumulative effect of a change in accounting for derivatives – net of income taxes of $9,892	–	–	(15,201)
Cumulative effect of a change in accounting for trading activities – net of income taxes of $43,123	–	(65,745)	–
NET INCOME	$ 240,579	$ 149,408	$ 312,166
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING – BASIC	91,265	84,903	84,718
WEIGHTED-AVERAGE COMMON SHARES OUTSTANDING – DILUTED	91,405	84,964	84,930
EARNINGS PER WEIGHTED-AVERAGE COMMON SHARE OUTSTANDING			
Income from continuing operations – basic	$ 2.53	$ 2.43	$ 3.86
Net income – basic	2.64	1.76	3.68
Income from continuing operations – diluted	2.52	2.43	3.85
Net income – diluted	2.63	1.76	3.68
DIVIDENDS DECLARED PER SHARE	$ 1.725	$ 1.625	$ 1.525

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS (dollars in thousands)

December 31,	2003	2002
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 228,779	$ 77,566
Customer and other receivables	365,732	362,587
Allowance for doubtful accounts	(9,223)	(9,607)
Accrued utility revenues	88,629	94,504
Materials and supplies (at average cost)	96,099	91,652
Fossil fuel (at average cost)	28,367	28,185
Deferred income taxes (Note 4)	–	4,094
Assets from risk management and trading activities (Note 18)	97,630	102,664
Real estate assets held for sale (Note 22)	–	42,339
Other current assets	73,034	66,388
Total current assets	969,047	860,372
INVESTMENTS AND OTHER ASSETS		
Real estate investments – net (Notes 1 and 6)	343,322	384,427
Assets from risk management and trading activities – long-term (Note 18)	138,946	191,754
Decommissioning trust accounts	240,645	194,440
Other assets	88,816	76,843
Total investments and other assets	811,729	847,464
PROPERTY, PLANT AND EQUIPMENT (NOTES 1, 6, 9, 10 AND 12)		
Plants in service and held for future use	9,925,344	9,058,900
Less accumulated depreciation and amortization	3,160,675	2,917,552
Total	6,764,669	6,141,348
Construction work in progress	554,876	777,542
Intangible assets, net of accumulated amortization	108,534	109,815
Nuclear fuel, net of accumulated amortization of $58,053 and $59,163	52,011	51,124
Net property, plant and equipment	7,480,090	7,079,829
DEFERRED DEBITS		
Regulatory assets (Notes 1, 3 and 4)	164,804	241,045
Other deferred debits	110,708	110,447
Total deferred debits	275,512	351,492
TOTAL ASSETS	$ 9,536,378	$ 9,139,157

See Notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS (dollars in thousands)

December 31,	2003	2002
LIABILITIES AND EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 293,427	$ 332,441
Accrued taxes	69,769	71,107
Accrued interest	51,625	53,018
Short-term borrowings (Note 5)	86,081	227,663
Current maturities of long-term debt (Note 6)	425,480	280,886
Customer deposits	49,783	42,190
Deferred income taxes (Note 4)	631	–
Liabilities from risk management and trading activities (Note 18)	92,755	111,329
Real estate liabilities held for sale (Note 22)	–	28,855
Other current liabilities	81,223	85,585
Total current liabilities	1,150,974	1,233,096
LONG-TERM DEBT LESS CURRENT MATURITIES (NOTE 6)	2,897,725	2,743,741
DEFERRED CREDITS AND OTHER		
Deferred income taxes (Note 4)	1,329,253	1,209,074
Regulatory liabilities (Notes 1, 3 and 4)	510,423	26,264
Liability for asset retirements and removals (Note 12)	234,440	600,431
Pension liability (Note 8)	188,041	183,580
Liabilities from risk management and trading activities – long-term (Note 18)	82,730	147,900
Unamortized gain – sale of utility plant (Note 9)	54,909	59,484
Other	258,104	249,134
Total deferred credits and other	2,657,900	2,476,167
COMMITMENTS AND CONTINGENCIES (NOTES 3, 11 AND 12)		
COMMON STOCK EQUITY (NOTE 7)		
Common stock, no par value; authorized 150,000,000 shares:		
Issued 91,379,947 at end of 2003 and 2002	1,744,354	1,737,258
Treasury stock at cost; 92,015 shares at end of 2003 and 124,830 shares at end of 2002	(3,273)	(4,358)
Total common stock	1,741,081	1,732,900
Accumulated other comprehensive income (loss):		
Minimum pension liability adjustment	(66,564)	(71,264)
Derivative instruments	27,563	(20,020)
Total accumulated other comprehensive loss	(39,001)	(91,284)
Retained earnings	1,127,699	1,044,537
Total common stock equity	2,829,779	2,686,153
TOTAL LIABILITIES AND EQUITY	$ 9,536,378	$ 9,139,157

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS (dollars in thousands)

Year Ended December 31,	2003	2002	2001
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$ 240,579	$ 149,408	$ 312,166
Adjustment to reconcile net income to net cash provided by operating activities:			
Gain on sale of discontinued operations	(10,003)	(6,955)	–
Cumulative effect of accounting change, net of tax	–	65,745	15,201
Depreciation and amortization	438,143	424,082	427,903
Nuclear fuel amortization	28,757	31,185	28,362
Allowance for equity funds used during construction	(14,240)	–	–
Deferred income taxes	81,756	191,135	(17,203)
Change in mark-to-market valuations	17,410	(18,146)	(133,573)
Redhawk Units 3 and 4 cancellation charge	–	49,192	–
Changes in current assets and liabilities:			
Customer and other receivables	(3,529)	40,343	146,581
Accrued utility revenues	5,875	(18,373)	(1,565)
Materials, supplies and fossil fuel	(4,629)	(11,599)	(16,867)
Other current assets	(6,646)	(7,247)	64
Accounts payable	(34,303)	54,592	(128,017)
Accrued taxes	(1,338)	(36,041)	7,483
Accrued interest	(1,193)	4,212	5,852
Other current liabilities	4,918	32,366	3,761
Proceeds from the sale of real estate assets	163,700	57,178	35,783
Real estate investments	(71,618)	(72,412)	(80,603)
Increase in regulatory assets	(11,697)	(11,029)	(17,516)
Change in risk management and trading – assets	46,911	(11,700)	(51,694)
Change in risk management and trading – liabilities	(11,613)	(22,783)	45,330
Change in customer advances	7,270	(23,780)	28,599
Change in pension liability	19,074	(3,009)	(30,205)
Change in other long-term assets	5,598	(23,554)	14,746
Change in other long-term liabilities	12,648	10,420	(23,345)
Net cash flow provided by operating activities	901,830	841,230	571,043
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	(693,475)	(895,522)	(1,055,574)
Capitalized interest	(29,444)	(43,749)	(47,862)
Proceeds from sale of assets from discontinued operations	27,193	28,917	–
Other	(21,040)	36,635	(16,481)
Net cash flow used for investing activities	(716,766)	(873,719)	(1,119,917)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of long-term debt	656,650	674,919	995,447
Short-term borrowings and payments – net	(173,303)	(306,079)	322,987
Dividends paid on common stock	(157,417)	(137,721)	(129,199)
Repayment of long-term debt	(368,162)	(351,545)	(621,057)
Common stock equity issuance	–	199,238	–
Other	8,181	2,624	(1,048)
Net cash flow (used for) provided by financing activities	(33,851)	81,436	567,130
NET INCREASE IN CASH AND CASH EQUIVALENTS	151,213	48,947	18,255
CASH AND CASH EQUIVALENTS AT BEGINNING OF YEAR	77,566	28,619	10,363
CASH AND CASH EQUIVALENTS AT END OF YEAR	$ 228,779	$ 77,566	$ 28,619
Supplemental disclosure of cash flow information			
Cash paid during the period for:			
Income taxes paid/(refunded)	$ 32,816	$ (17,918)	$ 223,037
Interest paid, net of amounts capitalized	$ 161,581	$ 126,322	$ 115,276

See Notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CHANGES IN COMMON STOCK EQUITY (dollars in thousands)

Year Ended December 31,	2003	2002	2001
COMMON STOCK (NOTE 7)			
Balance of beginning of year	$ 1,737,258	$ 1,536,924	$ 1,537,920
Issuance of common stock	–	199,238	–
Other	7,096	1,096	(996)
Balance at end of year	1,744,354	1,737,258	1,536,924
TREASURY STOCK (NOTE 7)			
Balance at beginning of year	(4,358)	(5,886)	(5,089)
Purchase of treasury stock	–	(5,971)	(16,393)
Reissuance of treasury stock used for stock compensation, net	1,085	7,499	15,596
Balance at end of year	(3,273)	(4,358)	(5,886)
RETAINED EARNINGS			
Balance at beginning of year	1,044,537	1,032,850	849,883
Net income	240,579	149,408	312,166
Common stock dividends	(157,417)	(137,721)	(129,199)
Balance at end of year	1,127,699	1,044,537	1,032,850
ACCUMULATED OTHER COMPREHENSIVE INCOME/(LOSS)			
Balance at beginning of year	(91,284)	(64,565)	–
Minimum pension liability adjustment, net of tax of $3,700, $46,109 and $634	4,700	(70,298)	(966)
Cumulative effect of a change in accounting for derivatives, net of tax of $47,404	–	–	72,274
Unrealized gain/(loss) on derivative instruments, net of tax of $33,298, $28,820 and $71,720	51,089	43,939	(109,346)
Reclassification of realized gain to income, net of tax of $2,343, $237 and $17,399	(3,506)	(360)	(26,527)
Balance at end of year	(39,001)	(91,284)	(64,565)
TOTAL COMMON STOCK EQUITY	$ 2,829,779	$ 2,686,153	$ 2,499,323
COMPREHENSIVE INCOME (LOSS)			
Net income	$ 240,579	$ 149,408	$ 312,166
Other comprehensive income (loss)	52,283	(26,719)	(64,565)
Comprehensive income	$ 292,862	$ 122,689	$ 247,601

See Notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Consolidation and Nature of Operations

The consolidated financial statements include the accounts of Pinnacle West and our subsidiaries: APS, Pinnacle West Energy, APS Energy Services, SunCor and El Dorado (principally NAC). Significant intercompany accounts and transactions between the consolidated companies have been eliminated.

APS is a vertically-integrated electric utility that provides either retail or wholesale electric service to substantially all of the state of Arizona, with the major exceptions of the Tucson metropolitan area and about one-half of the Phoenix metropolitan area. APS also generates, sells and delivers electricity to wholesale customers in the western United States. In early 2003, the marketing and trading division of Pinnacle West was moved to APS for future marketing and trading activities (existing wholesale contracts remained at Pinnacle West) as a result of the ACC's Track A Order prohibiting the previously required transfer of APS' generating assets to Pinnacle West Energy. See Note 3 for a discussion of the Track A Order. Pinnacle West Energy, which was formed in 1999, is the subsidiary through which we conduct our unregulated generation operations. APS Energy Services was formed in 1998 and provides competitive commodity energy and energy-related products to key customers in competitive markets in the western United States. SunCor is a developer of residential, commercial and industrial real estate projects in Arizona, New Mexico, Idaho and Utah. El Dorado is an investment firm, and its principal investment is in NAC, which is a company specializing in spent nuclear fuel technology.

Accounting Records and Use of Estimates

Our accounting records are maintained in accordance with accounting principles generally accepted in the United States of America (GAAP). The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. We have reclassified certain prior year amounts to conform to the current year presentation.

Derivative Accounting

We are exposed to the impact of market fluctuations in the commodity price and transportation costs of electricity, natural gas, coal and emissions allowances. We manage risks associated with these market fluctuations by utilizing various commodity instruments that qualify as derivatives, including exchange-traded futures and options and over-the-counter forwards, options and swaps. As part of our overall risk management program, we use such instruments to hedge purchases and sales of electricity, fuels, and emissions allowances and credits. In addition, subject to specified risk parameters monitored by the ERMC, we engage in marketing and trading activities intended to profit from market price movements.

We account for our derivative contracts in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 133 requires that entities recognize all derivatives as either assets or liabilities on the balance sheet and measure those instruments at fair value. Changes in the fair value of derivative instruments are either recognized periodically in income or, if hedge criteria are met, in common stock equity (as a component of other comprehensive income (loss)). SFAS No. 133 provides a scope exception for contracts that meet the normal purchases and sales criteria specified in the standard.

Prior to the fourth quarter of 2002, we accounted for our trading activity at fair value, with changes in fair value reported in earnings as required by EITF 98-10 "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." In the fourth quarter of 2002, we adopted EITF 02-3 "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," which rescinded EITF 98-10. We recorded a $66 million after-tax charge in net income as a cumulative effect adjustment for the previously recorded accumulated unrealized mark-to-market on energy trading contracts that did not meet the accounting definition of a derivative. Our energy trading contracts that are derivatives are accounted for at fair value under SFAS No. 133. Energy trading contracts that do not meet the definition of a derivative are now accounted for on an accrual basis with the associated revenues and costs recorded at the time the contracted commodities are delivered or received.

See Note 18 for additional information about our derivative and energy trading accounting policies.

Mark-to-Market Accounting

Under mark-to-market accounting, derivative contracts for the purchase or sale of energy commodities are reflected at fair market value, net of valuation adjustments, with resulting unrealized gains and losses recorded as current or long-term assets and liabilities from risk management and trading activities in the Consolidated Balance Sheets.

We determine fair market value using actively-quoted prices when available. We consider quotes for exchange-traded contracts and over-the-counter quotes obtained from independent brokers to be actively-quoted.

When actively-quoted prices are not available, we use prices provided by other external sources. This includes quarterly and calendar year quotes from independent brokers. We convert quarterly and calendar year quotes into monthly prices based on historical relationships.

For options, long-term contracts and other contracts for which price quotes are not available, we use models and other valuation methods. The valuation models we employ utilize spot prices, forward prices, historical market data and other factors to forecast future prices. The primary valuation technique we use to calculate the fair value of contracts where price quotes are not available is based on the extrapolation of forward pricing curves using observable market data for more liquid delivery points in the same region and actual transactions at the more illiquid delivery points. We also value option contracts using a variation of the Black-Scholes option-pricing model.

For non-exchange traded contracts, we calculate fair market value based on the average of the bid and offer price, and we discount to reflect net present value. We maintain certain valuation adjustments for a number of risks associated with the valuation of future commitments. These include valuation adjustments for liquidity and credit risks based on the financial condition of counterparties. The liquidity valuation adjustment represents the cost that would be incurred if all unmatched positions were closed-out or hedged.

The credit valuation adjustment represents estimated credit losses on our overall exposure to counterparties, taking into account netting arrangements, expected default experience for the credit rating of the counterparties and the overall diversification of the portfolio. Counterparties in the portfolio consist principally of major energy companies, municipalities and local distribution companies. We maintain credit policies that management believes minimize overall credit risk. Determination of the credit quality of counterparties is based upon a number of factors, including credit ratings, financial condition, project economics and collateral requirements. When applicable, we employ standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. See Note 18 for further discussion on credit risk.

The use of models and other valuation methods to determine fair market value often requires subjective and complex judgment. Actual results could differ from the results estimated through application of these methods. Our marketing and trading portfolio includes structured activities hedged with a portfolio of forward purchases that protects the economic value of the sales transactions. Our practice is to hedge within timeframes established by the ERMC.

Regulatory Accounting

APS is regulated by the ACC and the FERC. The accompanying financial statements reflect the rate-making policies of these commissions. For regulated operations, we prepare our financial statements in accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 requires a cost-based, rate-regulated enterprise to reflect the impact of regulatory decisions in its financial statements. As a result, we capitalize certain costs that would be included as expense in the current period by unregulated companies. Regulatory assets represent incurred costs that have been deferred because they are probable of future recovery in customer rates. Regulatory liabilities generally represent the recovery of expected future costs in current customer rates.

Management continually assesses whether our regulatory assets are probable of future recovery by considering factors such as applicable regulatory environment changes and recent rate orders to other regulated entities in the same jurisdiction. This determination reflects the current political and regulatory climate in the state and is subject to change in the future. If future recovery of costs ceases to be probable, the assets would be written off as a charge in current period earnings.

As part of the 1999 Settlement Agreement with the ACC (see Note 3), we continue to amortize certain regulatory assets over an eight-year period as follows (dollars in millions):

1999	2000	2001	2002	2003	2004	TOTAL
$164	$158	$145	$115	$86	$16	$686

The detail of regulatory assets is as follows (dollars in millions):

December 31,	2003	2002
Remaining balance recoverable under the 1999 Settlement Agreement (a)	$ 18	$ 104
Spent nuclear fuel storage (Note 11)	49	46
Electric industry restructuring transition costs (Note 3)	46	40
Deferred compensation	24	23
Contributions in aid of construction	11	10
Loss on reacquired debt (b)	12	9
Other	5	9
Total regulatory assets	$ 165	$ 241

(a) The majority of our unamortized regulatory assets above relates to deferred income taxes (see Note 4) and rate synchronization cost deferrals (see "Rate Synchronization Cost Deferrals" below).
(b) See "Reacquired Debt Costs" below.

The detail of regulatory liabilities is as follows (dollars in millions):

December 31,	2003	2002
Removal costs (a)	$ 480	$ –
Deferred gains on utility property	20	20
Deferred interest income (b)	8	–
Other	2	6
Total regulatory liabilities	$ 510	$ 26

(a) See Note 12 for information on Asset Retirement Obligations
(b) See "ACC Financing Orders" in Note 3 for information on the "APS Loan".

Rate Synchronization Cost Deferrals

As authorized by the ACC, operating costs (excluding fuel) and financing costs of Palo Verde Units 2 and 3 were deferred from the commercial operation dates (September 1986 for Unit 2 and January 1988 for Unit 3) until the date the units were included in a rate order (April 1988 for Unit 2 and December 1991 for Unit 3). In accordance with the 1999 Settlement Agreement, we are continuing to accelerate the amortization of the deferrals over an eight-year period that will end June 30, 2004. Amortization of the deferrals is included in depreciation and amortization expense in the Consolidated Statements of Income.

Utility Plant and Depreciation

Utility plant is the term we use to describe the business property and equipment that supports electric service, consisting primarily of generation, transmission and distribution facilities. We report utility plant at its original cost, which includes:

- material and labor;
- contractor costs;
- capitalized leases;
- construction overhead costs (where applicable); and
- capitalized interest or an allowance for funds used during construction.

We expense the costs of plant outages, major maintenance and routine maintenance as incurred. We charge retired utility plant to accumulated depreciation. Prior to 2003, we charged removal costs, less salvage, to accumulated depreciation. Effective January 1, 2003, we applied the provisions of SFAS 143 (see Note 12).

We record depreciation on utility plant on a straight-line basis over the remaining useful life of the related assets. The approximate remaining average useful lives of our utility property at December 31, 2003 were as follows:

- Fossil plant – 23 years;
- Nuclear plant – 20 years;
- Other generation – 29 years;
- Transmission – 36 years;
- Distribution – 23 years; and
- Other – 9 years.

For the years 2001 through 2003, the depreciation rates, as prescribed by our regulators, ranged from a low of 1.51% to a high of 12.5%. The weighted-average rate was 3.35% for 2003, 3.35% for 2002 and 3.40% for 2001. We depreciate non-utility property and equipment over the estimated useful lives of the related assets, ranging from 3 to 30 years.

El Dorado Investments

El Dorado accounts for its investments using the consolidated (if controlled), equity (if significant influence) and cost (less than 20% ownership) methods. Beginning in the third quarter of 2002, El Dorado began consolidating the operations of NAC.

Capitalized Interest

Capitalized interest represents the cost of debt funds used to finance construction projects. Plant construction costs, including capitalized interest, are expensed through depreciation when completed projects are placed into commercial operation. The rate used to calculate capitalized interest was a composite rate of 4.55% for 2003, 4.80% for 2002 and 6.13% for 2001. Capitalized interest ceases to accrue when construction is complete.

Allowance for Funds Used During Construction

AFUDC represents the approximate net composite interest cost of borrowed funds and a reasonable return on the equity funds used for construction of utility plant. Plant construction costs, including AFUDC, are recovered in authorized rates through depreciation when completed projects are placed into commercial operation.

AFUDC was calculated by using a composite rate of 8.55% for 2003. APS compounds AFUDC monthly and ceases to accrue AFUDC when construction work is completed and the property is placed in service.

In 2003, APS returned to the AFUDC method of capitalizing interest and equity costs associated with construction projects in a regulated utility. This is consistent with APS returning to a vertically-integrated utility, as evidenced by APS' recent general rate case filing, which includes the request for rate recognition of generation assets. Previously, APS capitalized interest in accordance with SFAS No. 34, "Capitalization of Interest Cost." Although AFUDC both increases the plant balance and results in higher current earnings during the construction period, AFUDC is realized in future revenues through depreciation provisions included in rates. This change increased earnings by $11 million in 2003 as compared to what it would have been under SFAS No. 34.

Electric Revenues

We derive electric revenues from sales of electricity to our regulated Native Load customers and sales to other parties from our marketing and trading activities. Revenues related to the sale of

electricity are generally recorded when service is rendered or electricity is delivered to customers. However, the determination and billing of electricity sales to individual Native Load customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of electricity delivered to customers since the date of the last meter reading and billing and the corresponding unbilled revenue are estimated. We exclude sales taxes on electric revenues from both revenue and taxes other than income taxes. Revenues from our Native Load customers and non-derivative instruments are reported on a gross basis in our Consolidated Statements of Income.

All gains and losses (realized and unrealized) on energy trading contracts that qualify as derivatives are included in marketing and trading segment revenues on the Consolidated Statements of Income on a net basis.

We adopted EITF 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not 'Held for Trading Purposes' As Defined in Issue No. 02-3," effective October 1, 2003. EITF 03-11 provides guidance on whether realized gains and losses on physically settled derivative contracts not held for trading purposes should be reported on a net or gross basis and concluded such classification is a matter of judgment that depends on the relevant facts and circumstances. In the electricity business, some contracts to purchase energy are netted against other contracts to sell energy. This is called "book-out" and usually occurs in contracts that have the same terms (quantities and delivery points) and for which power does not flow. We netted these book-outs reducing both revenues and purchased power and fuel costs in 2003, 2002 and 2001, but this did not impact our financial condition, net income or cash flows (see Note 18 for additional information).

SunCor

SunCor recognizes revenue from land, home and qualifying commercial operating assets sales in full, provided (a) the income is determinable, that is, the collectibility of the sales price is reasonably assured or the amount that will not be collectible can be estimated, and (b) the earnings process is virtually complete, that is, SunCor is not obligated to perform significant activities after the sale to earn the income. Unless both conditions exist, recognition of all or part of the income is postponed. SunCor recognizes income only after the assets' title has passed. A single method of recognizing income is applied to all sales transactions within an entire home, land or commercial development project. Commercial property and management revenues are recorded over the term of the lease or period in which services are provided. In addition, see Note 22 – Real Estate Activities – Discontinued Operations.

Percentage of Completion – NAC

Certain NAC contract revenues are accounted for under the percentage-of-completion method. These revenues are reported in other revenue on the Consolidated Statements of Income. Revenues are recognized based upon total costs incurred to date compared to total costs expected to be incurred for each contract. Revisions in contract revenue and cost estimates are reflected in the accounting period when known. Provisions are made for the full amounts of anticipated losses in the periods in which they are first determined. Changes in job performance, job conditions and estimated profitability, including those arising from contract penalty provisions and final contract settlements, may result in revisions to costs and income, and are recognized in the period in which revisions are determined. Profit incentives are included in revenues when their realization is reasonably assured.

Contract costs include all direct material and labor costs and those indirect costs related to contract performance, such as indirect labor, supplies, tools, repairs and depreciation costs. General and administrative costs are charged to expense as incurred.

Cash and Cash Equivalents

We consider all highly liquid investments purchased with an initial maturity of three months or less to be cash equivalents.

Nuclear Fuel

APS charges nuclear fuel to fuel expense by using the unit-of-production method. The unit-of-production method is an amortization method based on actual physical usage. APS divides the cost of the fuel by the estimated number of thermal units it expects to produce with that fuel. APS then multiplies that rate by the number of thermal units produced within the current period. This calculation determines the current period nuclear fuel expense.

APS also charges nuclear fuel expense for the permanent disposal of spent nuclear fuel. The DOE is responsible for the permanent disposal of spent nuclear fuel, and it charges APS $0.001 per kWh of nuclear generation. See Note 11 for information about spent nuclear fuel disposal and Note 12 for information on nuclear decommissioning costs.

Income Taxes

Income taxes are provided using the asset and liability approach prescribed by SFAS No. 109, "Accounting for Income Taxes." We file our federal income tax return on a consolidated basis and we file our state income tax returns on a consolidated or unitary basis. In accordance with our intercompany tax sharing agreement, federal and state income taxes are allocated to each subsidiary as though each first-tier subsidiary filed a separate income tax return. Any difference between that method and the consolidated (and unitary) income tax liability is attributed to the parent company. See Note 4.

Reacquired Debt Costs

For debt related to the regulated portion of APS' business, APS defers those gains and losses incurred upon early retirement and is seeking recovery in the APS general rate case (see Note 3). In accordance with the 1999 Settlement Agreement, APS is continuing to accelerate the amortization of reacquired debt costs over an eight-year period that will end June 30, 2004. All regulatory asset amortization is included in depreciation and amortization expense in the Consolidated Statements of Income.

Real Estate Investments

Real estate investments primarily include SunCor's land, home inventory and investments in joint ventures. Land includes acquisition costs, infrastructure costs, property taxes and capitalized interest directly associated with the acquisition and development of each project. Land under development and land held for future development are stated at accumulated cost, except that, to the extent that such land is believed to be impaired, it is written down to fair value. Land held for sale is stated at the lower of accumulated cost or estimated fair value less costs to sell. Home inventory consists of construction costs, improved lot costs, capitalized interest and property taxes on homes under construction. Home inventory is stated at the lower of accumulated cost or estimated fair value less costs to sell. Investments in joint ventures for which SunCor does not have a controlling financial interest are not consolidated but are accounted for using the equity method of accounting. In 2003, SunCor acquired two joint ventures for $10 million and consolidated $53 million of assets and $43 million of liabilities, which are included in the Consolidated Balance Sheets at December 31, 2003. The $10 million cash investment is included on the other investing line of the Consolidated Statements of Cash Flow at December 31, 2003. In addition, see Note 22 – Real Estate Activities – Discontinued Operations.

Stock-Based Compensation

In 2002, we began applying the fair value method of accounting for stock-based compensation, as provided for in SFAS No. 123, "Accounting for Stock-Based Compensation." The fair value method of accounting is the preferred method. In accordance with the transition requirements of SFAS No. 123, we applied the fair value method prospectively, beginning with 2002 stock grants. In prior years, we recognized stock compensation expense based on the intrinsic value method allowed in Accounting Principles Board Opinion (APB) No. 25, "Accounting for Stock Issued to Employees."

The following chart compares our net income, stock compensation expense and earnings per share to what those items would have been if we had recorded stock compensation expense based on the fair value method for all stock grants through 2003 (dollars in thousands, except per share amounts):

Year Ended December 31,	2003	2002	2001
Net Income as reported:	$240,579	$149,408	$312,166
Add: Stock compensation expense included in reported net income (net of tax)	1,286	300	–
Deduct: Total stock compensation expense determined under fair value method (net of tax)	(2,994)	(1,695)	(2,292)
Pro forma net income	$238,873	$148,013	$309,874
Earnings per share – basic:			
As reported	$ 2.64	$ 1.76	$ 3.68
Pro forma (fair value method)	$ 2.62	$ 1.74	$ 3.66
Earnings per share – diluted:			
As reported	$ 2.63	$ 1.76	$ 3.68
Pro forma (fair value method)	$ 2.61	$ 1.74	$ 3.65

In order to calculate the fair value of the 2003, 2002 and 2001 stock option grants and the pro forma information above, we calculated the fair value of each fixed stock option in the incentive plans using the Black-Scholes option-pricing model. The fair value was calculated based on the date the option was granted. The following weighted-average assumptions were also used in order to calculate the fair value of the stock options:

Year Ended December 31,	2003	2002	2001
Risk-free interest rate	3.35%	4.17%	4.08%
Dividend yield	5.26%	4.17%	3.70%
Volatility	38.03%	22.59%	27.66%
Expected life (months)	60	60	60

See Note 16 for further discussion about our stock compensation plans.

Intangible Assets

We have no goodwill recorded and have separately disclosed other intangible assets on our Consolidated Balance Sheets in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets." The intangible assets are amortized over their finite useful lives. The Company's gross intangible assets (which are primarily capitalized software costs) were $237 million at December 31, 2003 and $214 million at December 31, 2002. The related accumulated amortization was $128 million at December 31, 2003 and $104 million at December 31, 2002. Amortization expense was $25 million in 2003, $21 million in 2002, and $22 million in 2001. Estimated amortization expense on existing intangible assets over the next five years is $28 million in 2004, $27 million in 2005, $25 million in 2006, $20 million

in 2007, and $9 million in 2008. At December 31, 2003, the weighted average amortization period for intangible assets is 7 years.

2. ACCOUNTING MATTERS

See the following Notes for information about new accounting standards and other accounting matters:

- Note 8 for amended disclosure requirements (SFAS No. 132) on retirement plans and other benefits;
- Note 12 for a new accounting standard (SFAS No. 143) on asset retirement obligations;
- Note 16 for a new accounting standard (SFAS No. 148) related to stock-based compensation;
- Note 18 for EITF issues (EITF 02-3 and 03-11), DIG Issue No. C15, and a new accounting standard (SFAS No. 149) related to accounting for derivatives and energy contracts;
- Note 20 for a new FASB interpretation (FIN No. 46R) related to VIEs;
- Note 21 for a new FASB interpretation (FIN No. 45) on guarantees; and
- Note 22 for a standard (SFAS No. 144) on accounting for the impairment or disposal of long-lived assets.

3. REGULATORY MATTERS

Electric Industry Restructuring

State

1999 Settlement Agreement The following are the major provisions of the 1999 Settlement Agreement, as approved by the ACC:

- APS has reduced rates for standard-offer service for customers with loads less than three MW in a series of annual retail electricity price reductions of 1.5% on July 1 for each of the years 1999 to 2003 for a total of 7.5%. Based on the price reductions authorized in the 1999 Settlement Agreement, there were retail price decreases of approximately $24 million ($14 million after taxes), effective July 1, 1999; approximately $28 million ($17 million after taxes), effective July 1, 2000; approximately $27 million ($16 million after taxes), effective July 1, 2001; approximately $28 million ($17 million after taxes), effective July 1, 2002; and approximately $29 million ($18 million after taxes), effective July 1, 2003. For customers having loads of three MW or greater, standard-offer rates have been reduced in varying annual increments that total 5% in the years 1999 through 2002.
- Unbundled rates being charged by APS for competitive direct access service (for example, distribution services) became effective upon approval of the 1999 Settlement Agreement, retroactive to July 1, 1999, and also became subject to annual reductions beginning January 1, 2000, that vary by rate class, through January 1, 2004.
- There is a moratorium on retail price changes for standard-offer and unbundled competitive direct access services until July 1, 2004, except for the price reductions described above and certain other limited circumstances. Neither the ACC nor APS is prevented from seeking or authorizing rate changes prior to July 1, 2004 in the event of conditions or circumstances that constitute an emergency, such as an inability to finance on reasonable terms; material changes in APS' cost of service for ACC-regulated services resulting from federal, tribal, state or local laws; regulatory requirements; or judicial decisions, actions or orders.
- APS will be permitted to defer for later recovery prudent and reasonable costs of complying with the Rules, system benefits costs in excess of the levels included in then-current (1999) rates, and costs associated with the "provider of last resort" and standard-offer obligations for service after July 1, 2004. These costs are to be recovered through an adjustment clause or clauses commencing on July 1, 2004. See "APS General Rate Case and Retail Rate Adjustment Mechanisms" below.
- APS' distribution system opened for retail access effective September 24, 1999. Customers were eligible for retail access in accordance with the phase-in adopted by the ACC under the Rules (see "Retail Electric Competition Rules" below), including an additional 140 MW being made available to eligible non-residential customers. APS opened its distribution system to retail access for all customers on January 1, 2001. The regulatory developments and legal challenges to the Rules discussed in this Note have raised considerable uncertainty about the status and pace of electric competition and of electric restructuring in Arizona. Although some very limited retail competition existed in APS' service area in 1999 and 2000, there are currently no active retail competitors providing unbundled energy or other utility services to APS' customers. As a result, we cannot predict when, and the extent to which, additional competitors will re-enter APS' service territory.
- Prior to the 1999 Settlement Agreement, APS was recovering substantially all of its regulatory assets through July 1, 2004, pursuant to a 1996 regulatory agreement. In addition, the 1999 Settlement Agreement states that APS has demonstrated that its allowable stranded costs, after mitigation and exclusive of regulatory assets, are at least $533 million net present value (in 1999 dollars). The 1999 Settlement Agreement also states that APS will not be allowed to recover $183 million net present value (in 1999 dollars) of the $533 million. The 1999 Settlement Agreement provides that APS will have the opportunity to recover $350 million net present value (in 1999 dollars) through a competitive transition charge that will remain in effect through December 31,

2004, at which time it will terminate. The costs subject to recovery under the adjustment clause described above will be decreased or increased by any over/under-recovery of the $350 million due to sales volume variances. As discussed below under "APS General Rate Case and Retail Rate Adjustment Mechanisms," APS is seeking to recover amounts written off by APS as a result of the 1999 Settlement Agreement.

- The 1999 Settlement Agreement required APS to form, or cause to be formed, a separate corporate affiliate or affiliates and transfer to such affiliate(s) its competitive electric assets and services no later than December 31, 2002. The 1999 Settlement Agreement provided that APS would be allowed to defer and later collect, beginning July 1, 2004, 67% of its costs to accomplish the required transfer of generation assets to an affiliate. However, as discussed below, in 2002 the ACC unilaterally modified this aspect of the 1999 Settlement Agreement by issuing the Track A Order, an order preventing APS from transferring its generation assets. APS is seeking to recover all costs incurred by APS in preparation for the previously anticipated transfer of generation assets to Pinnacle West Energy. See "APS General Rate Case and Retail Rate Adjustment Mechanisms" below.

Retail Electric Competition Rules The Rules approved by the ACC include the following major provisions:

- They apply to virtually all Arizona electric utilities regulated by the ACC, including APS.
- Effective January 1, 2001, retail access became available to all APS retail electricity customers.
- Electric service providers that get CC&N's from the ACC can supply only competitive services, including electric generation, but not electric transmission and distribution.
- Affected utilities must file ACC tariffs that unbundle rates for noncompetitive services.
- The ACC shall allow a reasonable opportunity for recovery of unmitigated stranded costs.
- Absent an ACC waiver, prior to January 1, 2001, each affected utility (except certain electric cooperatives) must transfer all competitive electric assets and services to an unaffiliated party or parties or to a separate corporate affiliate or affiliates. Under the 1999 Settlement Agreement, APS received a waiver to allow transfer of its competitive electric assets and services to affiliates no later than December 31, 2002. However, as discussed below, in 2002 the ACC reversed its decision, as reflected in the Rules, to require APS to transfer its generation assets.

Under the 1999 Settlement Agreement, the Rules are to be interpreted and applied, to the greatest extent possible, in a manner consistent with the 1999 Settlement Agreement. If the two cannot be reconciled, APS must seek, and the other parties to the 1999 Settlement Agreement must support, a waiver of the Rules in favor of the 1999 Settlement Agreement.

On November 27, 2000, a Maricopa County, Arizona, Superior Court judge issued a final judgment holding that the Rules are unconstitutional and unlawful in their entirety due to failure to establish a fair value rate base for competitive electric service providers and because certain of the Rules were not submitted to the Arizona Attorney General for certification. The judgment also invalidates all ACC orders authorizing competitive electric service providers, including APS Energy Services, to operate in Arizona. We do not believe the ruling affects the 1999 Settlement Agreement. The 1999 Settlement Agreement was not at issue in the consolidated cases before the judge. Further, the ACC made findings related to the fair value of APS' property in the order approving the 1999 Settlement Agreement. The ACC and other parties aligned with the ACC appealed the ruling to the Arizona Court of Appeals, and in January 2004, the Court invalidated some, but not all, of the Rules as either violative of Arizona's constitutional requirement that the ACC consider the "fair value" of a utility's property in setting rates or as being beyond the ACC's constitutional and statutory powers. Other Rules were set aside for failure to submit such regulations to the Arizona Attorney General for approval as required by statute.

Provider of Last Resort Obligation Although the Rules allow retail customers to have access to competitive providers of energy and energy services, APS is, under the Rules, the "provider of last resort" for standard-offer, full-service customers under rates that have been approved by the ACC. These rates are established until at least July 1, 2004. The 1999 Settlement Agreement allows APS to seek adjustment of these rates in the event of emergency conditions or circumstances, such as the inability to secure financing on reasonable terms; material changes in APS' cost of service for ACC-regulated services resulting from federal, tribal, state or local laws; regulatory requirements; or judicial decisions, actions or orders. Energy prices in the western wholesale market vary and, during the course of the last two years, have been volatile. At various times, prices in the spot wholesale market have significantly exceeded the amount included in APS' current retail rates. In the event of shortfalls due to unforeseen increases in load demand or generation or transmission outages, APS may need to purchase additional supplemental power in the wholesale spot market. Unless APS is able to obtain an adjustment of its rates under the emergency provisions of the 1999 Settlement Agreement, there can be no assurance that APS would be able to fully recover the costs of this power. See "APS General Rate Case and Retail Rate Adjustment Mechanisms" below for a discussion of retail rate adjustment mechanisms that were the subject of ACC hearings in April 2003.

Track A Order On September 10, 2002, the ACC issued the Track A Order, in which the ACC, among other things:

- reversed its decision, as reflected in the Rules, to require APS to transfer its generation assets either to an unrelated third party or to a separate corporate affiliate; and
- unilaterally modified the 1999 Settlement Agreement, which authorized APS' transfer of its generating assets, and directed APS to cancel its activities to transfer its generation assets to Pinnacle West Energy.

On November 15, 2002, APS filed appeals of the Track A Order in the Maricopa County, Arizona Superior Court and in the Arizona Court of Appeals. Arizona Public Service Company vs. Arizona Corporation Commission. CV 2002-0222 32. Arizona Public Service Company vs. Arizona Corporation Commission. 1CA CC 02-0002. On December 13, 2002, APS and the ACC staff agreed to principles for resolving certain issues raised by APS in its appeals of the Track A Order. APS and the ACC are the only parties to the Track A Order appeals. The major provisions of the principles include, among other things, the following:

- APS and the ACC staff agreed that it would be appropriate for the ACC to consider the following matters in APS' general rate case, which was filed on June 27, 2003:
  - the generating assets to be included in APS' rate base, including the question of whether the PWEC Dedicated Assets should be included in APS' rate base;
  - the appropriate treatment of the $234 million pretax asset write-off agreed to by APS as part of the 1999 Settlement Agreement; and
  - the appropriate treatment of costs incurred by APS in preparation for the previously anticipated transfer of generation assets to Pinnacle West Energy.
- Upon the ACC's issuance of a final decision that is no longer subject to appeal approving APS' request to provide $500 million of financing or credit support to Pinnacle West Energy or the Company, with appropriate conditions, APS' appeals of the Track A Order would be limited to the issues described in the preceding bullet points, each of which would be presented to the ACC for consideration prior to any final judicial resolution. As noted below, the ACC issued the Financing Order on April 4, 2003. The Financing Order is final and no longer subject to appeal. As a result, APS' appeals of the Track A Order are limited to the issues described in the preceding bullet points.

On August 27, 2003, APS, Pinnacle West and Pinnacle West Energy filed a lawsuit asserting damage claims relating to the Track A Order. Arizona Public Service Company et al. v. The State of Arizona ex rel., Superior Court of the State of Arizona, County of Maricopa, No. CV2003-016372.

Track B Order On March 14, 2003, the ACC issued the Track B Order, which required APS to solicit bids for certain estimated amounts of capacity and energy for periods beginning July 1, 2003. For 2003, APS was required to solicit competitive bids for about 2,500 MW of capacity and about 4,600 gigawatt-hours of energy, or approximately 20% of APS' total retail energy requirements. The bid amounts are expected to increase in 2004 and 2005 based largely on growth in APS' retail load and APS' retail energy sales. The Track B Order also confirmed that it was "not intended to change the current rate base status of [APS'] existing assets."

The order recognizes APS' right to reject any bids that are unreasonable, uneconomical or unreliable. The ACC staff and an independent monitor participated in the Track B procurement process. The Track B Order also contains requirements relating to standards of conduct between APS and any affiliate of APS participating in the competitive solicitation, requires that APS treat bidders in a non-discriminatory manner and requires APS to file a protocol regarding short-term and emergency procurements. The order permits the provision by APS of corporate oversight, support and governance as long as such activities do not favor Pinnacle West Energy in the procurement process or provide Pinnacle West Energy with confidential APS bidding information that is not available to other bidders. The order directs APS to evaluate bids on cost, reliability and reasonableness. The decision requires bidders to allow the ACC to inspect their plants and requires assurances of appropriate competitive market conduct from senior officers of such bidders. Following the solicitation, the decision requires APS to prepare a report evaluating environmental issues relating to the procurement, and a series of workshops on environmental risk management will be commenced thereafter.

APS issued requests for proposals in March 2003 and, by May 6, 2003, APS entered into contracts to meet all or a portion of its requirements for the years 2003 through 2006 as follows:

(1) Pinnacle West Energy agreed to provide 1,700 MW in July through September of 2003 and in June through September of 2004, 2005 and 2006, by means of a unit contingent contract.

(2) PPL EnergyPlus, LLC agreed to provide 112 MW in July through September of 2003 and 150 MW in June through September of 2004 and 2005, by means of a unit contingent contract.

(3) Panda Gila River LP agreed to provide 450 MW in October of 2003 and 2004 and May of 2004 and 2005, and 225 MW from November 2003 through April 2004 and from November 2004 through April 2005, by means of firm call options.

ACC Financing Orders On April 4, 2003, the ACC issued the Financing Order authorizing APS to lend up to $500 million to Pinnacle West Energy, guarantee up to $500 million of Pinnacle West Energy debt, or a combination of both, not to exceed $500 million in the aggregate (the "APS Loan"), subject to the following principal conditions:

- any debt issued by APS pursuant to the order must be unsecured;
- the APS Loan must be callable and secured by the PWEC Dedicated Assets;
- the APS Loan must bear interest at a rate equal to 264 basis points above the interest rate on APS debt that could be issued and sold on equivalent terms (including, but not limited to, maturity and security);
- the 264 basis points referred to in the previous bullet point will be capitalized as a deferred credit and used to offset retail rates in the future, with the deferred credit balance bearing an interest rate of six percent per annum;
- the APS Loan must have a maturity date of not more than four years, unless otherwise ordered by the ACC;
- any demonstrable increase in APS' cost of capital as a result of the transaction (such as from a decline in bond rating) will be excluded from future rate cases;
- APS must maintain a common equity ratio of at least forty percent and may not pay common dividends if such payment would reduce its common equity ratio below that threshold, unless otherwise waived by the ACC. The ACC will process any waiver request within sixty days, and for this sixty-day period this condition will be suspended. However, this condition, which will continue indefinitely, will not be permanently waived without an order of the ACC; and
- certain waivers of the ACC's affiliated interest rules previously granted to APS and its affiliates will be temporarily withdrawn and, during the term of the APS Loan, neither Pinnacle West nor Pinnacle West Energy may reorganize or restructure, acquire or divest assets, or form, buy or sell affiliates (each, a "Covered Transaction"), or pledge or otherwise encumber the Pinnacle West Energy assets without prior ACC approval, except that the foregoing restrictions will not apply to the following categories of Covered Transactions:
  - Covered Transactions less than $100 million, measured on a cumulative basis over the calendar year in which the Covered Transactions are made;
  - Covered Transactions by SunCor of less than $300 million through 2005, consistent with SunCor's anticipated accelerated asset sales activity during those years;
  - Covered Transactions related to the payment of ongoing construction costs for Pinnacle West Energy's (a) West Phoenix Unit 5, located in Phoenix, and (b) Silverhawk plant, located near Las Vegas, with an expected commercial operation date in mid-2004; and
  - Covered Transactions related to the sale of 25% of the Silverhawk plant to SNWA pursuant to an agreement between SNWA and Pinnacle West Energy.

The ACC also ordered the ACC staff to conduct an inquiry into our and our affiliates' compliance with the retail electric competition and related rules and decisions. On June 13, 2003, APS submitted its report on these matters to the ACC staff. The ACC has indicated that the preliminary investigation would be addressed in the pending general rate case (see below).

On May 12, 2003, APS issued $500 million of debt pursuant to the Financing Order and made a $500 million loan to Pinnacle West Energy. Pinnacle West Energy distributed the net proceeds of that loan to us to fund the repayment of a portion of the debt we incurred to finance the construction of the PWEC Dedicated Assets. See Note 6.

On November 22, 2002, the ACC issued an order approving APS' request to permit APS to make short-term advances to Pinnacle West in the form of an interaffiliate line of credit in the amount of $125 million. As of December 31, 2003, there were no borrowings outstanding under this financing arrangement, and this authority expired on December 4, 2003.

APS General Rate Case and Retail Rate Adjustment Mechanisms As noted above, on June 27, 2003, APS filed a general rate case with the ACC and requested a $175.1 million, or 9.8%, increase in its annual retail electricity revenues, to become effective July 1, 2004. In this rate case, APS updated its cost of service and rate design.

Major Components of the Request The major reasons for the request include:

- complying with the provisions of the 1999 Settlement Agreement;
- incorporating significant increases in fuel and purchased power costs, including results of purchases through the ACC's Track B procurement process;
- recognizing changes in APS' cost of service, cost allocation and rate design;
- obtaining rate recognition of the PWEC Dedicated Assets;
- recovering $234 million written off by APS as a result of the 1999 Settlement Agreement; and

- recovering restructuring and compliance costs associated with the ACC's Rules.

Requested Rate Increase The requested rate increase totals $175.1 million, or 9.8%, and is comprised of the following items (dollars in millions):

	Annual Revenue	Percent
Increase in base rates	$ 166.8	9.3%
Rules compliance charge	8.3	0.5%
Total increase	$ 175.1	9.8%

Test Year The filing is based on an adjusted historical test year ended December 31, 2002.

Cost of Capital The proposed weighted average cost of capital for the test year ended December 31, 2002 is 8.67%, including an 11.5% return on equity.

Rate Base The request is based on a rate base of $4.2 billion, calculated using Original Cost Less Depreciation ("OCLD") methodology. The OCLD rate base approximates the ACC-jurisdictional portion of the net book value of utility plant, net of accumulated depreciation and deferred taxes, as of December 31, 2002, except as set forth below.

The requested rate base includes the PWEC Dedicated Assets, with a total combined capacity of approximately 1,800 MW. These assets were included at their estimated July 1, 2004 net book value. Upon approval of the request, the PWEC Dedicated Assets would be transferred to APS from Pinnacle West Energy.

The filing also includes calculated amounts for Fair Value Rate Base and Replacement Cost New Depreciated ("RCND") rate base. The ACC is required by the Arizona Constitution to make a finding of Fair Value Rate Base, which has traditionally been defined by the ACC as the arithmetic average of OCLD rate base and RCND rate base.

Recovery of Previous $234 Million Write-Off The request includes recovery, over a fifteen year period, of the write-off of $234 million pretax of regulatory assets by APS as a result of the 1999 Settlement Agreement. See "1999 Settlement Agreement" above.

Estimated Timeline APS has asked the ACC to approve the requested rate increase by July 1, 2004. The ACC ALJ has issued a procedural schedule setting a hearing date on the application of May 25, 2004. Based on the schedule and existing ACC regulations, we believe the ACC will be able to make a decision in this general rate case by the end of 2004.

The general rate case also addresses the implementation of rate adjustment mechanisms that were the subject of ACC hearings in April 2003. The rate adjustment mechanisms, which were authorized as a result of the 1999 Settlement Agreement, would allow APS to recover several types of costs, the most significant of which are power supply costs (fuel and purchased power costs) and costs associated with complying with the Rules.

On November 4, 2003, the ACC approved the issuance of an order which authorizes a rate adjustment mechanism allowing APS to recover changes in purchased power costs (but not changes in fuel costs) incurred after July 1, 2004. The other rate adjustment mechanisms authorized in the 1999 Settlement Agreement (such as the costs associated with complying with the ACC electric competition rules) were also tentatively approved for subsequent implementation in the general rate case. The provisions of this order will not become effective until there is a final order in the general rate case, and the ACC further reserved the right to amend, modify or reconsider, in its entirety, this November 4 order during the rate case.

Testimony As required by the procedural schedule, on February 3, 2004, the following parties filed their initial written testimony with the ACC on all issues except cost of service (i.e., cost allocation among customer classes) and rate design:

- the ACC "litigation" staff;
- the Arizona Residential Utility Consumers Office ("RUCO"), an office established by the Arizona legislature to represent the interests of residential utility consumers before the ACC; and
- other approved rate case interveners.

ACC Staff Recommendations In its filed testimony, the ACC staff recommended, among other things, that the ACC:

- decrease APS' annual retail electricity revenues by at least $142.7 million, which would result in a rate decrease of approximately 8%, based on a 9% return on equity;
- not allow the PWEC Dedicated Assets to be included in APS' rate base;
- not allow APS to recover any of the $234 million written off as a result of the 1999 Settlement Agreement; and
- not implement any adjustment mechanisms for fuel and purchased power.

The ACC staff recommendations, if implemented as proposed, could have a material adverse impact on our results of operations, financial position, liquidity, dividend sustainability, credit ratings, and access to capital markets. We believe that APS' rate case requests are supported by, among other things, APS' demonstrated need for the PWEC Dedicated Assets; APS' need to attract capital at reasonable rates of return to support the required capital investment to ensure continued customer reliability in APS' high-growth service territory; and the conditions in the western energy market. As a result, we believe it is unlikely that the ACC would adopt the ACC staff recommendations in their present form, although we can give no assurances in that regard.

The ACC staff also submitted testimony indicating that APS and its affiliates had violated the "spirit, if not the letter" of the Rules, the Code of Conduct and the 1999 Settlement Agreement.

RUCO Recommendations In its filed testimony, RUCO recommended, among other things, that the ACC:

- decrease APS' annual retail electricity revenues by $53.6 million, which would result in a rate decrease of approximately 2.84%, based on a 9.5% return on equity;
- not allow the PWEC Dedicated Assets to be included in APS' rate base;
- not allow APS to recover any of the $234 million written off as a result of the 1999 Settlement Agreement; and
- not implement any adjustment mechanisms for fuel and purchased power.

APS believes that its rate request is necessary to ensure APS' continued ability to reliably serve one of the fastest growing regions in the country and views any ultimate decision that would deny recovery of the Company's investment in the PWEC Dedicated Assets as constituting a regulatory "taking." APS will vigorously oppose the recommendations of the ACC staff, RUCO, and other parties offering similar recommendations.

Request for Proposals In early December 2003, APS issued a request for proposals ("RFP") for long-term power supply resources, and on January 8, 2004, an ACC Administrative Law Judge issued an order requiring, among other things, APS to file a summary of the proposals with the ACC. On January 27, 2004, APS filed a summary of the proposals with the ACC. APS is negotiating with certain of the parties that submitted proposals.

Federal

In July 2002, the FERC adopted a price mitigation plan that constrains the price of electricity in the wholesale spot electricity market in the western United States. The FERC adopted a price cap of $250 per MWh for the period subsequent to October 31, 2002. Sales at prices above the cap must be justified and are subject to potential refund.

On July 31, 2002, the FERC issued a Notice of Proposed Rulemaking for Standard Market Design for wholesale electric markets. Voluminous comments and reply comments were filed on virtually every aspect of the proposed rule. On April 28, 2003, the FERC Staff issued an additional white paper on the proposed Standard Market Design. The white paper discusses several policy changes to the proposed Standard Market Design, including a greater emphasis on flexibility for regional needs. We cannot currently predict what, if any, impact there may be to the Company if the FERC adopts the proposed rule or any modifications proposed in the comments.

General

The regulatory developments and legal challenges to the Rules discussed in this Note have raised considerable uncertainty about the status and pace of retail electric competition and of electric restructuring in Arizona. Although some very limited retail competition existed in APS' service area in 1999 and 2000, there are currently no active retail competitors providing unbundled energy or other utility services to APS' customers. As a result, we cannot predict when, and the extent to which, additional competitors will re-enter APS' service territory. As competition in the electric industry continues to evolve, we will continue to evaluate strategies and alternatives that will position us to compete in the new regulatory environment.

4. INCOME TAXES

Certain assets and liabilities are reported differently for income tax purposes than they are for financial statements. The tax effect of these differences is recorded as deferred taxes. We calculate deferred taxes using the current income tax rates.

APS has recorded a regulatory asset related to income taxes on its Balance Sheets in accordance with SFAS No. 71. This regulatory asset is for certain temporary differences, primarily the allowance for equity funds used during construction. APS amortizes this amount as the differences reverse. In accordance with ACC settlement agreements, APS is continuing to accelerate amortization of a regulatory asset related to income taxes over an eight-year period that will end June 30, 2004 (see Note 1). Accordingly, we are including this accelerated amortization in depreciation and amortization expense on our Consolidated Statements of Income.

As a result of a change in IRS guidance, we claimed a tax deduction related to an APS tax accounting method change on the 2001 federal consolidated income tax return. The accelerated deduction resulted in a $200 million reduction in the current income tax liability and a corresponding increase in the plant-related deferred tax liability. In 2002, we received an income tax refund of approximately $115 million related to our 2001 federal consolidated income tax return. In 2003, we resolved certain prior-year issues with the taxing authorities and recorded an $18 million tax benefit associated with tax credits and other reductions to income tax expense.

The components of income tax expense for income from continuing operations are as follows (dollars in thousands):

Year Ended December 31,	2003	2002	2001
Current:			
Federal	$ 22,875	$ (43,492)	$ 184,893
State	929	(15,415)	45,845
Total current	23,804	(58,907)	230,738
Deferred	81,756	191,135	(17,203)
Total income tax expense	$ 105,560	$132,228	$213,535

The following chart compares pretax income at the 35% federal income tax rate to income tax expense (dollars in thousands):

Year Ended December 31,	2003	2002	2001
Federal income tax expense at 35% statutory rate	$ 117,648	$118,449	$189,316
Increases (reductions) in tax expense resulting from:			
State income tax net of federal income tax benefit	14,353	15,796	23,353
Credits and favorable adjustments related to prior years resolved in 2003	(17,944)	–	–
Allowance for equity funds used during construction (see Note 1)	(5,616)	–	–
Other	(2,881)	(2,017)	866
Income tax expense	$ 105,560	$132,228	$213,535

The following table sets forth the net deferred income tax liability recognized on the Consolidated Balance Sheets (dollars in thousands):

December 31,	2003	2002
Current asset/(liability)	$ (631)	$ 4,094
Long term liability	(1,329,253)	(1,209,074)
Accumulated deferred income taxes – net	$ (1,329,884)	$(1,204,980)

The components of the net deferred income tax liability were as follows (dollars in thousands):

December 31,	2003	2002
DEFERRED TAX ASSETS		
Pension liability	$ 73,844	$ 72,835
Risk management and trading activities	59,293	43,542
Regulatory liabilities:		
Federal excess deferred income taxes	18,936	20,867
Other	33,542	9,818
Deferred gain on Palo Verde Unit 2 sale leaseback	21,656	23,562
Other	64,769	69,236
Total deferred tax assets	272,040	259,880
DEFERRED TAX LIABILITIES		
Plant-related	(1,448,730)	(1,316,636)
Regulatory assets	(69,070)	(101,522)
Risk management and trading activities	(84,124)	(46,702)
Total deferred tax liabilities	(1,601,924)	(1,464,860)
Accumulated deferred income taxes – net	$ (1,329,884)	$ (1,204,980)

5. LINES OF CREDIT AND SHORT-TERM BORROWINGS

APS had committed lines of credit with various banks of $250 million at December 31, 2003 and 2002, which were available either to support the issuance of commercial paper or to be used for bank borrowings. The current line matures in May 2004, and the document allows for a 364-day extension of the termination date without lender consent. The commitment fees at December 31, 2003 and 2002 for these lines of credit were 0.175% and 0.09% per annum. APS had no bank borrowings outstanding under these lines of credit at December 31, 2003 and 2002.

APS had no commercial paper borrowings outstanding at December 31, 2003 and 2002. By Arizona statute, APS' short-term borrowings cannot exceed 7% of its total capitalization unless approved by the ACC.

Pinnacle West had committed lines of credit of $275 million at December 31, 2003 and $475 million at December 31, 2002, which were available either to support the issuance of commercial paper or to be used for bank borrowings. The current lines mature in November and December of 2004 and the $150 million facility allows for a 364-day extension of the termination date without lender consent. Pinnacle West had no outstanding borrowings at December 31, 2003 and $72 million was outstanding at December 31, 2002. The commitment fees ranged from 0.125% to 0.175% in 2003 and ranged from 0.10% to 0.15% in 2002. Pinnacle West had no commercial paper borrowings outstanding at December 31, 2003. Commercial paper borrowings outstanding were $24 million at December 31, 2002. The weighted average interest rate on commercial paper borrowings was 2.06% for the year ended December 31, 2002.

All APS and Pinnacle West bank lines of credit and commercial paper agreements are unsecured.

On November 22, 2002, the ACC approved APS' request to permit APS to make short-term advances to Pinnacle West in the form of an inter-affiliate line of credit in the amount of $125 million. This interim loan matured in December 2003, and there were never any borrowings on this line.

SunCor had revolving lines of credit totaling $120 million at December 31, 2003 and $140 million at December 31, 2002. The commitment fees were 0.125% in 2003 and 2002. SunCor had $50 million outstanding at December 31, 2003 and $126 million outstanding at December 31, 2002. The weighted-average interest rate was 4.50% at December 31, 2003 and was 3.75% at December 31, 2002. Interest for 2003 and 2002 was based on LIBOR plus 2% or prime plus 0.5%. The balance is included in short-term debt on the Consolidated Balance Sheets. SunCor had other short-term loans in the amount of $36 million at December 31, 2003 and $6 million outstanding at December 31, 2002. These loans are made up of multiple notes primarily with variable interest rates based on LIBOR plus 2.5% at December 31, 2003 and 2002. In addition, two notes acquired in 2003 had interest rates of 3.37% and 3.87%.

6. LONG-TERM DEBT

Borrowings under the APS mortgage bond indenture are secured by substantially all utility plant. APS also has unsecured debt. SunCor's short and long-term debt is collateralized by interests in certain real property and Pinnacle West's debt is unsecured. The following table presents the components of long-term debt on the Consolidated Balance Sheets outstanding at December 31, 2003 and 2002 (dollars in thousands):

December 31,	Maturity Dates (a)	Interest Rates	2003	2002
APS				
First mortgage bonds	2004	6.625%	$ 80,000	$ 80,000
	2023	7.25% (b)	–	54,150
	2025	8.0% (c)	–	33,075
	2028	5.5%	25,000	25,000
	2028	5.875%	154,000	154,000
Unamortized discount and premium			(8,631)	(6,337)
Pollution control bonds	2024-2034	(d)	366,860	366,860
Pollution control bonds with senior notes (e)	2029	5.05%	90,000	90,000
Unsecured notes	2004	5.875%	125,000	125,000
Unsecured notes	2005	6.25%	100,000	100,000
Unsecured notes	2005	7.625%	300,000	300,000
Unsecured notes	2011	6.375%	400,000	400,000
Unsecured notes	2012	6.50%	375,000	375,000
Unsecured notes	2033	5.625%	200,000	–
Unsecured notes	2015	4.650%	300,000	–
Senior notes (f)	2006	6.75%	83,695	83,695
Capitalized lease obligations	2004-2012	(g)	11,749	20,400
Subtotal			2,622,673	2,220,843
SUNCOR				
Notes payable	2004-2008	(h)	17,125	7,647
Capitalized lease obligations	2004-2005	8.91%	728	1,299
Subtotal			17,853	8,946
PINNACLE WEST				
Senior notes	2004-2006	(i)	515,000	540,000
Unamortized discount and premium			(270)	(530)
Floating rate notes	2003	(j)	–	250,000
Floating senior notes	2005	(k)	165,000	–
Capitalized lease obligations	2004-2007	5.48%	1,243	1,999
Subtotal			680,973	791,469
EL DORADO				
Construction loan	2005	1.22%	1,600	2,600
Capitalized lease obligations	2004-2005	(l)	106	771
Subtotal			1,706	3,371
Total long-term debt			3,323,205	3,024,629
Less current maturities			425,480	280,888
TOTAL LONG-TERM DEBT LESS CURRENT MATURITIES			$ 2,897,725	$ 2,743,741

(a) This schedule does not reflect the timing of redemptions that may occur prior to maturity.

(b) On August 15, 2003, APS redeemed at maturity $54 million of its First Mortgage Bonds, 7.25% Series due 2023.

(c) On April 7, 2003, APS redeemed $33 million of its First Mortgage Bonds, 8.00% Series due 2025.

(d) The weighted-average rate was 1.51% at December 31, 2003 and 1.94% at December 31, 2002. Changes in short-term interest rates would affect the costs associated with this debt.

(e) On November 1, 2002, Maricopa County, Arizona Pollution Control Corporation issued $90 million of 5.05% Pollution Control Revenue Refunding Bonds (Arizona Public Service Company Palo Verde Project) 2002 Series A, due 2029, and loaned the proceeds to APS pursuant to a loan agreement. The bonds were issued to refinance $90 million of outstanding pollution control bonds. The bondholders were issued $90 million of first mortgage bonds (senior note mortgage bonds) as collateral.

(f) APS currently has outstanding $84 million of first mortgage bonds (senior note mortgage bonds) issued to the senior note trustee as collateral for the senior notes, as well as the $90 million issue discussed in footnote (e) above. The senior note mortgage bonds have the same interest rate, interest payment dates, maturity and redemption provisions as the senior notes. APS' payments of principal, premium and/or interest on the senior notes satisfy its corresponding payment obligations on the senior note mortgage bonds. As long as the senior note mortgage bonds secure the senior notes, the senior notes will effectively rank equally with the first mortgage bonds. When APS repays all of its first mortgage bonds, other than those that secure senior notes, the senior note mortgage bonds will no longer secure the senior notes and will cease to be outstanding

(g) The weighted average rate was 5.55% at December 31, 2003 and 5.73% at December 31, 2002. Capital leases are included in property, plant and equipment on the Consolidated Balance Sheets for both December 31, 2003 and December 31, 2002.

(h) Multiple notes with variable interest rates based on the lenders' prime plus 0.25%, lenders' prime plus 1.75% and LIBOR plus 2.5%. There is also one note at a fixed rate of 7.00%.

(i) Includes two series of notes: $300 million at 6.4% due in 2006 and $215 million at 4.5% due in 2024 as of December 31, 2002. In December 2003, we repaid the $25 million note. On January 29, 2004, we entered into a fixed-for-floating interest rate swap transaction on the $300 million 6.4% note. The transaction qualifies as a fair value hedge under SFAS No. 133.

(j) The weighted average rate was 2.35% at December 31, 2002. Interest for 2002 was based on LIBOR plus 0.98%. In June 2003, we repaid the $250 million floating note.

(k) The weighted average rate was 1.960% at December 31, 2003. Interest for 2003 was based on LIBOR plus 0.80%.

(l) The weighted average rate was 7.0% at December 31, 2003 and 7.04% at December 31, 2002.

Pinnacle West's and APS' debt covenants related to their respective financing arrangements include a debt-to-total-capitalization ratio and an interest coverage test. Pinnacle West and APS comply with these covenants and each anticipates it will continue to meet the covenant requirement levels. The ratio of debt to total capitalization cannot exceed 65% for each of the Company and APS individually. At December 31, 2003, the ratio was approximately 54% for Pinnacle West. At December 31, 2003, the ratio was approximately 53% for APS. The provisions regarding interest coverage require a minimum cash coverage of two times the interest requirements for each of the Company and APS. Based on 2003 results, the coverages were approximately 4 times for the Company, 4 times for the APS bank agreements and 15 times for the APS mortgage indenture. Failure to comply with such covenant levels would result in an event of default which, generally speaking, would require the immediate repayment of the debt subject to the covenants.

Neither Pinnacle West's nor APS' financing agreements contain "ratings triggers" that would result in an acceleration of the required interest and principal payments in the event of a ratings downgrade. However, in the event of a ratings downgrade, Pinnacle West and/or APS may be subject to increased interest costs under certain financing agreements.

All of Pinnacle West's bank agreements contain "cross-default" provisions that would result in defaults and the potential acceleration of payment under those loan agreements if Pinnacle West or APS were to default under other agreements. All of APS' bank agreements contain cross-default provisions that would result in defaults and the potential acceleration of payment under these bank agreements if APS were to default under other agreements. Pinnacle West's and APS' credit agreements generally contain provisions under which the lenders could refuse to advance loans in the event of a material adverse change in our financial condition or financial prospects.

The following is a list of payments due on total long-term debt and capitalized lease requirements through 2008:

- $425 million in 2004;
- $569 million in 2005;
- $395 million in 2006;
- $2 million in 2007;
- $6 million in 2008; and
- $1,935 million, thereafter.

APS' first mortgage bondholders share a lien on substantially all utility plant assets (other than nuclear fuel and transportation equipment and other excluded assets). The mortgage bond indenture restricts the payment of common stock dividends under certain conditions. APS may pay dividends on its common stock if there is a sufficient amount "available" from retained earnings and the excess of cumulative book depreciation (since the mortgage's inception) over mortgage depreciation, which is the cumulative amount of additional property pledged each year to address collateral depreciation. As of December 31, 2003, the amount "available" under the mortgage would have allowed APS to pay approximately $3 billion of dividends compared to APS' current annual common stock dividends of $170 million.

The mortgage currently constitutes a lien on substantially all of the property of APS. We anticipate that in early April 2004, all first mortgage bonds issued by APS under its existing mortgage and deed of trust, other than the first mortgage bonds securing APS' senior notes, will have been paid and retired. At that time, APS' obligation to make payment on the first mortgage bonds securing the senior notes will also be deemed to be satisfied and discharged and the senior note first mortgage bonds will cease to secure the senior notes. APS is then obligated to take all steps necessary to terminate its existing mortgage and deed of trust and cannot issue any additional first mortgage bonds under that mortgage.

7. COMMON STOCK AND TREASURY STOCK

Our common stock and treasury stock activity during each of the three years 2003, 2002 and 2001 is as follows (dollars in thousands):

	Common Stock Shares	Common Stock Amount	Treasury Stock Shares	Treasury Stock Amount
Balance at December 31, 2000	84,824,947	$ 1,537,920	(109,638)	$ (5,089)
Purchase of treasury stock	–	–	(334,600)	(16,393)
Reissuance of treasury stock for stock compensation (net)	–	–	342,931	15,596
Other	–	(996)	–	–
Balance at December 31, 2001	84,824,947	1,536,924	(101,307)	(5,886)
Common stock issuance – December 23, 2002	6,555,000	199,238	–	–
Purchase of treasury stock	–	–	(150,500)	(5,971)
Reissuance of treasury stock for stock compensation (net)	–	–	126,977	7,499
Other	–	1,096	–	–
Balance at December 31, 2002	91,379,947	1,737,258	(124,830)	(4,358)
Reissuance of treasury stock for stock compensation (net)	–	–	32,815	1,085
Other	–	7,096	–	–
Balance at December 31, 2003	91,379,947	$ 1,744,354	(92,015)	$ (3,273)

8. RETIREMENT PLANS AND OTHER BENEFITS

Pinnacle West sponsors a qualified defined benefit pension plan and a non-qualified supplemental excess benefit retirement plan for the employees of Pinnacle West and our subsidiaries. Effective January 1, 2003, Pinnacle West sponsored a new account balance plan for all new employees in place of the defined benefit plan, and, as of April 1, 2003, the plan was offered as an alternative to the defined benefit plan for all existing employees. A defined benefit plan specifies the amount of benefits a plan participant is to receive using information about the participant. The pension plan covers nearly all of our employees.The supplemental excess benefit retirement plan covers officers of the Company and highly compensated employees designated for participation by the Board of Directors. Our employees do not contribute to the plans. Generally, we calculate the benefits based on age, years of service and pay.

Pinnacle West also sponsors other postretirement benefits for the employees of Pinnacle West and our subsidiaries. We provide medical and life insurance benefits to retired employees. Employees must retire to become eligible for these retirement benefits, which are based on years of service and age. For the medical insurance plans, retirees make contributions to cover a portion of the plan costs. For the life insurance plan, retirees do not make contributions. We retain the right to change or eliminate these benefits.

In December 2003, FASB revised SFAS No. 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits," to enhance disclosures of relevant accounting information by providing additional information on plan assets, obligations, cash flows, and net cost. The revisions are reflected in this Note. Pinnacle West uses a December 31 measurement date for its plans.

On December 8, 2003, the President signed the "Medicare Prescription Drug, Improvement and Modernization Act of 2003" (the Act). One feature of the Act is a government subsidy of prescription drug costs. We have not yet quantified the effect, if any, on accumulated projected benefit obligation or the net periodic postretirement benefit cost in our financial statements and accompanying notes. Specific accounting guidance for this subsidy, including transition rules, is pending.

The following table provides details of the plan's benefit costs. Also included is the portion of these costs charged to expense, including administrative costs and excluding amounts capitalized as overhead construction or billed to electric plant participants (dollars in thousands):

	Pension			Other Benefits		
	2003	2002	2001	2003	2002	2001
Service cost – benefits earned during the period	$ 37,662	$ 30,333	$ 27,640	$ 15,858	$ 12,036	$ 9,438
Interest cost on benefit obligation	76,951	71,242	66,549	30,163	25,235	21,585
Expected return on plan assets	(65,046)	(75,652)	(77,340)	(18,762)	(21,116)	(21,985)
Amortization of:						
Transition (asset)/obligation	(3,227)	(3,227)	(3,227)	3,005	4,001	7,698
Prior service cost/(credit)	2,401	2,912	3,008	(125)	(75)	–
Net actuarial loss/(gain)	18,135	1,846	907	9,714	3,072	(4,066)
Net periodic benefit cost	$ 66,876	$ 27,454	$ 17,537	$ 39,853	$ 23,153	$ 12,670
Portion of cost charged to expense	$ 30,094	$ 13,727	$ 8,944	$ 17,934	$ 11,577	$ 6,462

The following table sets forth the plan's change in the benefit obligations for the plan years 2003 and 2002 (dollars in thousands):

	Pension		Other Benefits	
Year Ended December 31,	2003	2002	2003	2002
Benefit obligation at January 1	$ 1,069,577	$ 931,646	$ 409,874	$ 318,355
Service cost	37,662	30,333	15,858	12,036
Interest cost	76,951	71,242	30,163	25,235
Benefit payments	(43,869)	(35,230)	(15,749)	(10,473)
Actuarial losses	171,420	71,696	106,475	108,979
Plan amendments	(4,113)	(110)	(6,440)	(44,258)(a)
Benefit obligation at December 31	$ 1,307,628	$ 1,069,577	$ 540,161	$ 409,874

(a) The plan was amended in January 2002 to increase the deductibles, out-of-pocket maximums and prescription drug co-pays. The plan was amended in June 2002 to increase the participants' portion of premiums.

The following table sets forth the qualified defined benefit plan and other benefit plan changes in the fair value of plan assets for the years 2003 and 2002 (dollars in thousands):

	Pension		Other Benefits	
Year Ended December 31,	2003	2002	2003	2002
Fair value of plan assets at January 1	$ 720,807	$ 764,873	$ 223,474	$ 237,810
Actual gain/(loss) on plan assets	162,571	(36,966)	46,071	(27,802)
Employer contributions	46,000	26,600	39,852	23,600
Benefit payments	(42,067)	(33,700)	(15,346)	(10,134)
Fair value of plan assets at December 31	$ 887,311	$ 720,807	$ 294,051	$ 223,474

The following table shows a reconciliation of the funded status of the plans to the amounts recognized in the Consolidated Balance Sheets as of December 31, 2003 and 2002 (dollars in thousands):

	Pension		Other Benefits	
December 31,	2003	2002	2003	2002
Funded status at December 31	$ (420,317)	$ (348,770)	$ (246,130)	$ (166,400)
Unrecognized net transition (asset)/obligation	(7,099)	(10,327)	27,044	36,489
Unrecognized prior service cost/(credit)	16,634	23,148	(1,547)	(1,673)
Unrecognized net actuarial losses/(gains)	348,982	293,223	217,611	148,268
Benefit liability recognized in the Consolidated Balance Sheet	$ (61,800)	$ (42,726)	$ (3,022)	$ (3,316)

The following sets forth the details related to benefits included on the Consolidated Balance Sheets (dollars in thousands):

	Pension		Other Benefits	
December 31,	2003	2002	2003	2002
Accrued benefit cost	$ (61,800)	$ (42,726)	$ (3,022)	$ (3,316)
Additional minimum liability	(126,241)	(141,154)	–	–
Total liability	(188,041)	(183,880)	(3,022)	(3,316)
Intangible asset	16,634	23,147	–	–
Accumulated other comprehensive income (pretax)	109,607	118,007	–	–
Net amount recognized	$ (61,800)	$ (42,726)	$ (3,022)	$ (3,316)

The following table sets forth the other comprehensive income arising from the change in additional minimum liability for the years ended December 31, 2003 and 2002 (dollars in thousands):

Year Ended December 31,	2003	2002
Decrease/(Increase) in minimum liability included in other comprehensive income – net of tax	$ 4,700	$ (70,298)

The following table sets forth the projected benefit obligation and the accumulated benefit obligation for pension plans in excess of plan assets for the plan years 2003 and 2002 (dollars in thousands):

Year Ended December 31,	2003	2002
Projected benefit obligation	$ 1,307,628	$ 1,069,577
Accumulated benefit obligation	$ 1,075,352	$ 904,687
Less fair value of plan assets	887,311	720,807
Pension liability	$ 188,041	$ 183,880

Below are the weighted-average assumptions for both the pension and other benefits used to determine each respective benefit obligation and net periodic benefit cost:

	Benefit Obligations As of December 31,		Benefit Costs For the Years Ended December 31,	
	2003	2002	2003	2002
Discount rate	6.10%	6.75%	6.75%	7.50%
Rate of compensation increase	4.00%	4.00%	4.00%	4.00%
Expected long-term return on plan assets	9.00%	9.00%	9.00%	10.00%
Initial health care cost trend rate	8.00%	8.00%	8.00%	7.00%
Ultimate health care cost trend rate	5.00%	5.00%	5.00%	5.00%
Year ultimate health care cost trend rate is reached	2008	2007	2007	2006

In selecting the pretax expected long-term rate of return on plan assets we consider past performance and economic forecasts for the types of investments held by the plan. For the year 2003, we decreased our pretax expected long-term rate of return on plan assets from 10% to 9%, as a result of continued declines in general equity and bond market conditions. For the year 2004 we are assuming a 9% rate of return on plan assets. This rate is reflective of the market returns earned historically on our target asset allocation. As recent history has demonstrated, markets may decline and increase dramatically. However, the long-term rate of return on plan assets of 9% is reasonable given our asset allocation in relation to historical and expected future performance.

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A 1% change in the assumed initial and ultimate health care cost trend rates would have the following effects (dollars in millions):

	1% Increase	1% Decrease
Effect on other postretirement benefits expense, after consideration of amounts capitalized or billed to electric plant participants	$ 7	$ (5)
Effect on service and interest cost components of net periodic other postretirement benefit costs	$ 9	$ (7)
Effect on the accumulated other postretirement benefit obligation	$ 95	$ (76)

Plan Assets

Pinnacle West's qualified pension plan asset allocation at December 31, 2003, and 2002 is as follows:

	Percentage of Plan Assets at December 31,		Target Asset Allocation
	2003	2002	
Asset Category:			
Equity securities	65%	56%	50 – 70%
Debt securities	23	31	20 – 40%
Other	12	13	5 – 15%
Total	100%	100%	

The Board of Directors has established an investment policy for the pension plan assets and has delegated oversight of the plan assets to an Investment Management Committee.The investment policy sets forth the objective of providing for future pension benefits by maximizing return consistent with a stated tolerance of risk. The primary investment strategies are diversification of assets, stated asset allocation targets and ranges, prohibition of investments in Pinnacle West securities, and external management of plan assets.

Pinnacle West's other postretirement benefit plan asset allocation at December 31, 2003, and 2002, is as follows:

	Percentage of Plan Assets at December 31,		Target Asset Allocation
	2003	2002	
Asset Category:			
Equity securities	71%	62%	60 – 80%
Fixed Income	25	34	20 – 35%
Other	4	4	1 – 6%
Total	100%	100%	

The Investment Management Committee, described above, has also been delegated oversight of the plan assets for the postretirement benefit plans. The investment policy for other post retirement benefit plan assets is similar to that of the pension plan assets described above.

Contributions

Under current law, we are required to contribute approximately $100 million to our pension plans in 2004 and expect to contribute approximately $50 million to our other postretirement benefit plans in 2004. If currently pending legislation is enacted, our required pension contribution in 2004 would decrease to the $25 to $50 million range.

Employee Savings Plan Benefits

Pinnacle West sponsors a defined contribution savings plan for eligible employees of Pinnacle West and subsidiaries. In a defined contribution savings plan, the benefits a participant receives result from regular contributions participants make to their own individual account. Under this plan, the Company matches a percentage of the participants' contributions in the form of Pinnacle West stock. After a five year vesting period, participants have an option to

transfer the Company matching contributions out of the Pinnacle West Stock Fund to other investment funds within the plan. At December 31, 2003, approximately 23% of total plan assets were in Pinnacle West stock. We recorded expenses for this plan of approximately $5 million for each of the years 2003, 2002 and 2001.

Severance Charges

In July 2002, we implemented a voluntary workforce reduction as part of our cost reduction program. We recorded $36 million before taxes in voluntary severance costs in 2002. No further charges are expected.

9. LEASES

In 1986, APS sold about 42% of its share of Palo Verde Unit 2 and certain common facilities in three separate sale leaseback transactions. APS accounts for these leases as operating leases. The gain resulting from the transaction of approximately $140 million was deferred and is being amortized to operations and maintenance expense over 29.5 years, the original term of the leases. There are options to renew the leases for two additional years and to purchase the property for fair market value at the end of the lease terms. Consistent with the ratemaking treatment, a regulatory asset is recognized for the difference between lease payments and rent expense calculated on a straight-line basis. See Note 20 for a discussion of VIEs, including the SPEs involved in the Palo Verde sale leaseback transactions.

In addition, we lease certain land, buildings, equipment, vehicles and miscellaneous other items through operating rental agreements with varying terms, provisions and expiration dates.

Total lease expense recognized in the Consolidated Statements of Income was $67 million in 2003, $67 million in 2002 and $59 million in 2001.

The amounts to be paid for the Palo Verde Unit 2 leases are approximately $49 million per year for the years 2004 to 2015.

In accordance with the 1999 Settlement Agreement and previous settlement agreements, APS is continuing to accelerate amortization of the regulatory asset for leases over an eight-year period that will end June 30, 2004 (see Note 1). All regulatory asset amortization is included in depreciation and amortization expense in the Consolidated Statements of Income. The balance of this regulatory asset at December 31, 2003 was $5 million.

Estimated future minimum lease payments for our operating leases are approximately as follows (dollars in millions):

Year		
2004	$	73
2005		70
2006		68
2007		66
2008		66
Thereafter		421
Total future lease commitments	$	764

10. JOINTLY-OWNED FACILITIES

APS shares ownership of some of its generating and transmission facilities with other companies. The following table shows APS' interest in those jointly-owned facilities recorded on the Consolidated Balance Sheets at December 31, 2003. APS' share of operating and maintaining these facilities is included in the Consolidated Statements of Income in operations and maintenance expense (dollars in thousands):

	Percent Owned by APS	Plant In Service	Accumulated Depreciation	Construction Work In Progress
Generating Facilities:				
Palo Verde Nuclear Generating Station Units 1 and 3	29.1%	$ 1,880,218	$ (867,322)	$ 21,620
Palo Verde Nuclear Generating Station Unit 2 (see Note 9)	17.0%	681,744	(242,131)	9,771
Four Corners Steam Generating Station Units 4 and 5	15.0%	154,111	(81,369)	2,580
Navajo Steam Generating Station Units 1, 2, and 3	14.0%	242,987	(111,744)	2,352
Cholla Steam Generating Station Common Facilities (a)	62.4%(b)	78,500	(44,379)	1,338
Transmission Facilities:				
ANPP 500KV System	35.8%(b)	68,457	(27,050)	40
Navajo Southern System	31.4%(b)	26,903	(17,971)	128
Palo Verde – Yuma 500KV System	23.9%(b)	9,583	(4,364)	602
Four Corners Switchyards	27.5%(b)	2,852	(1,734)	–
Phoenix – Mead System	17.1%(b)	36,418	(3,567)	–
Palo Verde – Estrella 500KV System	55.5%(b)	70,972	(1,615)	1,632
Palo Verde SE Valley Project	15.0%(b)	–	–	648

(a) PacifiCorp owns Cholla Unit 4 and APS operates the unit for PacifiCorp. The common facilities at the Cholla Plant are jointly-owned.
(b) Weighted average of interests

11. COMMITMENTS AND CONTINGENCIES

Enron

We recorded charges totaling $21 million before income taxes for exposure to Enron and its affiliates in the fourth quarter of 2001. This amount is comprised of a $15 million reserve for the Company's net exposure to Enron and its affiliates and additional expenses of $6 million primarily related to 2002 power contracts with Enron that were canceled. These charges take into consideration our rights of set-off with respect to the Enron related contractual obligations. The APS portion of the write-off was $13 million. The basis of the set-offs included, but was not limited to, provisions in the various contractual arrangements with Enron and its affiliates, including an International Swaps and Derivative Agreement (ISDA) between APS and Enron North America. The write-off is also net of the expected recovery based on secondary market quotes from the bond market. The amounts were written-off from the balances of the related assets and liabilities from risk management and trading activities on the Consolidated Balance Sheets. In February 2004, Enron filed an adversary proceeding against APS in bankruptcy court regarding differences in the valuation of trading positions involving APS. Enron North America v. Arizona Public Service Company, Adversary Proceeding No. 04-02366 (ALJ). APS will vigorously defend this action and does not believe it will have any material adverse impact on its anticipated exposure to Enron described above.

Palo Verde Nuclear Generating Station

Spent Fuel and Waste Disposal

Nuclear power plant operators are required to enter into spent fuel disposal contracts with the DOE, and the DOE is required to accept and dispose of all spent nuclear fuel and other high-level radioactive wastes generated by domestic power reactors. Although the Nuclear Waste Act required the DOE to develop a permanent repository for the storage and disposal of spent nuclear fuel by 1998, the DOE has announced that the repository cannot be completed before 2010 and it does not intend to begin accepting spent nuclear fuel prior to that date. In November 1997, the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) issued a decision preventing the DOE from excusing its own delay, but refused to order the DOE to begin accepting spent nuclear fuel. Based on this decision and the DOE's delay, a number of utilities, including APS (on behalf of itself and the other Palo Verde owners), filed damages actions against the DOE in the Court of Federal Claims. Arizona Public Service Company v. United States of America, United States Court of Federal Claims, 03-2632C.

In February 2002, the Secretary of Energy recommended to President Bush that the Yucca Mountain, Nevada site be developed as a permanent repository for spent nuclear fuel. The President transmitted this recommendation to Congress and the State of Nevada vetoed the President's recommendation. Congress approved the Yucca Mountain site, overriding the Nevada veto. It is now expected that the DOE will submit a license application to the NRC in late 2004. The State of Nevada has filed several lawsuits relating to the Yucca Mountain site. We cannot currently predict what further steps will be taken in this area.

APS has existing fuel storage pools at Palo Verde and is operating a new facility for on-site dry storage of spent nuclear fuel. With the existing storage pools and the addition of the new facility, APS believes spent nuclear fuel storage or disposal methods will be available for use by Palo Verde to allow its continued operation through the term of the operating license for each Palo Verde unit.

Although some low-level waste has been stored on-site in a low-level waste facility, APS is currently shipping low-level waste to off-site facilities. APS currently believes interim low-level waste storage methods are or will be available for use by Palo Verde to allow its continued operation and to safely store low-level waste until a permanent disposal facility is available.

APS currently estimates it will incur $115 million (in 2003 dollars) over the life of Palo Verde for its share of the costs related to the on-site interim storage of spent nuclear fuel. As of December 31, 2003, APS had spent $7 million and recorded a liability of $42 million for on-site interim spent nuclear fuel storage costs related to nuclear fuel burned to date. APS has recorded a corresponding regulatory asset of $49 million and is seeking recovery of these costs through future rates (see "APS General Rate Case and Retail Rate Mechanisms" in Note 3).

APS has reclassified prior year spent nuclear fuel costs of approximately $44 million previously included in accumulated amortization of nuclear fuel to the liability for asset retirements and removals on our Consolidated Balance Sheets at December 31, 2002. Upon adoption of SFAS No. 143 in 2003, APS reclassified this liability to a regulatory liability because no legal obligation for removal exists.

APS believes that scientific and financial aspects of the issues of spent nuclear fuel and low-level waste storage and disposal can be resolved satisfactorily. However, APS acknowledges that their ultimate resolution in a timely fashion will require political resolve and action on national and regional scales which APS is less able to predict. APS expects to vigorously protect and pursue its rights related to this matter.

Nuclear Insurance

The Palo Verde participants have insurance for public liability resulting from nuclear energy hazards to the full limit of liability under federal law. This potential liability is covered by primary liability insurance provided by commercial insurance carriers in the amount of $300 million and the balance by an industry-wide retrospective assessment program. If losses at any nuclear power plant covered by the programs exceed the accumulated funds, APS

could be assessed retrospective premium adjustments. The maximum assessment per reactor under the program for each nuclear incident is approximately $101 million, subject to an annual limit of $10 million per incident. Based on APS' interest in the three Palo Verde units, APS' maximum potential assessment per incident for all three units is approximately $88 million, with an annual payment limitation of approximately $9 million.

The Palo Verde participants maintain "all risk" (including nuclear hazards) insurance for property damage to, and decontamination of, property at Palo Verde in the aggregate amount of $2.75 billion, a substantial portion of which must first be applied to stabilization and decontamination. APS has also secured insurance against portions of any increased cost of generation or purchased power and business interruption resulting from a sudden and unforeseen outage of any of the three units. The insurance coverage discussed in this and the previous paragraph is subject to certain policy conditions and exclusions.

Purchased Power and Fuel Commitments

APS and Pinnacle West are parties to various purchased power and fuel contracts with terms expiring from 2004 through 2025 that include required purchase provisions. We estimate the contract requirements to be approximately $209 million in 2004; $66 million in 2005; $66 million in 2006; $51 million in 2007; $51 million in 2008 and $461 million thereafter. However, these amounts may vary significantly pursuant to certain provisions in such contracts that permit us to decrease required purchases under certain circumstances.

Of the various purchased power and fuel contracts mentioned above some of those contracts have take-or-pay provisions. The contracts APS has for the supply of its coal and nuclear fuel supply have take-or-pay provisions. The current take-or-pay coal contracts have terms that expire in 2016. The current take-or-pay nuclear fuel contracts expire in 2004 and had not been renewed as of December 31, 2003.

The following table summarizes the estimated take-or-pay commitments for the existing terms (dollars in millions):

Estimated Years Ending December 31,	2004	2005	2006	2007	2008	Thereafter
Coal	$ 41	$ 42	$ 43	$ 44	$ 43	$306
Nuclear	11	–	–	–	–	–
Total take-or-pay commitments (a)	$ 52	$ 42	$ 43	$ 44	$ 43	$306

(a) Total take-or-pay commitments are approximately $530 million. The total net present value of these commitments is approximately $340 million.

Coal Mine Reclamation Obligations

APS must reimburse certain coal providers for amounts incurred for coal mine reclamation. Our coal mine reclamation obligation was $60 million at December 31, 2003 and $59 million at December 31, 2002 and is included in deferred credits-other in the Consolidated Balance Sheets.

A regulatory asset has been established for amounts not yet recovered from ratepayers related to the coal obligations. In accordance with the 1999 Settlement Agreement with the ACC, APS is continuing to accelerate the amortization of the regulatory asset for coal mine reclamation over an eight-year period that will end June 30, 2004. Amortization is included in depreciation and amortization expense on the Consolidated Statements of Income.

California Energy Market Issues and Refunds in the Pacific Northwest

In July 2001, the FERC ordered an expedited fact-finding hearing to calculate refunds for spot market transactions in California during a specified time frame. APS was a seller and a purchaser in the California markets at issue, and to the extent that refunds are ordered, APS should be a recipient as well as a payor of such amounts. The FERC is still considering the evidence and refund amounts have not yet been finalized. APS does not anticipate material changes in its exposure and still believes, subject to the finalization of the revised proxy prices, that it will be entitled to a net refund.

The FERC also ordered an evidentiary proceeding to discuss and evaluate possible refunds for the Pacific Northwest. The FERC affirmed the ALJ's conclusion that the prices in the Pacific Northwest were not unreasonable or unjust and refunds should not be ordered in this proceeding. This decision has now been appealed to the Court of Appeals (Ninth Circuit).

Although the FERC ruling in the Pacific Northwest matter is being appealed and the FERC has not yet calculated the specific refund amounts due in California, we do not expect that the resolution of these issues, as to the amounts alleged in the proceedings, will have a material adverse impact on our financial position, results of operations or liquidity.

On March 26, 2003, FERC made public a Final Report on Price Manipulation in Western Markets, prepared by its Staff and covering spot markets in the West in 2000 and 2001. The report stated that a significant number of entities who participated in the California markets during the 2000-2001 time period, including APS, may potentially have been involved in arbitrage transactions that allegedly violated certain provisions of the ISO tariff. APS and the FERC staff have settled this matter, and the settlement was approved by the FERC.

SCE and PG&E have publicly disclosed that their liquidity has been materially and adversely affected because of, among other things, their inability to pass on to ratepayers the prices each has paid for energy and ancillary services procured through the PX and the ISO. PG&E filed for bankruptcy protection in 2001.

We are closely monitoring developments in the California energy market and the potential impact of these developments on us and our subsidiaries. Based on our evaluations, we previously reserved $10 million before income taxes for our credit exposure related to the California energy situation, $5 million of which was recorded in the fourth quarter of 2000 and $5 million of which was recorded in the first quarter of 2001. Our evaluations took into consideration our range of exposure of approximately zero to $38 million before income taxes and a review of likely recovery rates in bankruptcy situations.

In the second quarter of 2002, PG&E filed its Modified Second Amended Disclosure Statement and the CPUC filed its Alternative Plan of Reorganization. Both plans generally indicated that PG&E would, at the close of bankruptcy proceedings, be able to pay in full all outstanding, undisputed debts. As a result of these developments, the probable range of our total exposure now is approximately zero to $27 million before income taxes, and our best estimate of the probable loss is now approximately $6 million before income taxes. Consequently, we reversed $4 million of the $10 million reserve in the second quarter of 2002. We cannot predict with certainty, however, the impact that any future resolution or attempted resolution, of the California energy market situation may have on us, our subsidiaries or the regional energy market in general.

California Energy Market Litigation

On March 19, 2002, the State of California filed a complaint with the FERC alleging that wholesale sellers of power and energy, including the Company, failed to properly file rate information at the FERC in connection with sales to California from 2000 to the present. State of California v. British Columbia Power Exchange et al., Docket No. EL02-71-000. The complaint requests the FERC to require the wholesale sellers to refund any rates that are "found to exceed just and reasonable levels." This complaint has been dismissed by the FERC and the State of California is now appealing the matter to the Ninth Circuit Court of Appeals. In addition, the State of California and others have filed various claims, which have now been consolidated, against several power suppliers to California alleging antitrust violations. Wholesale Electricity Antitrust Cases I and II, Superior Court in and for the County of San Diego, Proceedings Nos. 4204-00005 and 4204-00006. Two of the suppliers who were named as defendants in those matters, Reliant Energy Services, Inc. (and other Reliant entities) and Duke Energy and Trading, LLP (and other Duke entities), filed cross-claims against various other participants in the PX and California independent system operator markets, including APS, attempting to expand those matters to such other participants. APS has not yet filed a responsive pleading in the matter, but APS believes the claims by Reliant and Duke as they relate to APS are without merit.

APS was also named in a lawsuit regarding wholesale contracts in California, which has now been moved back to state court. James Millar, et al. v. Allegheny Energy Supply, et al., San Francisco Superior Court, Case No. 407867. The First Amended Complaint alleges basically that the contracts entered into were the result of an unfair and unreasonable market, in violation of California unfair competition laws. The PX has filed a lawsuit against the State of California regarding the seizure of forward contracts and the State has filed a cross complaint against APS and numerous other PX participants. Cal PX v. The State of California, Superior Court in and for the County of Sacramento, JCCP No. 4203. Various motions continue to be filed, and we currently believe these claims will have no material adverse impact on our financial position, results of operations or liquidity.

Citizens Power Service Agreement

By letter dated March 7, 2001, Citizens, which owns a utility in Arizona, advised APS that it believes APS overcharged Citizens by over $50 million under a power service agreement. APS believes its charges under the agreement were fully in accordance with the terms of the agreement. In addition, in testimony filed with the ACC on March 13, 2002, Citizens acknowledged, based on its review, "if Citizens filed a complaint with the FERC, it probably would lose the central issue in the contract interpretation dispute." APS and Citizens terminated the power service agreement effective July 15, 2001. In replacement of the power service agreement, the Company and Citizens entered into a power sale agreement under which the Company will supply Citizens with future specified amounts of electricity and ancillary services through May 31, 2008. This new agreement does not address issues previously raised by Citizens with respect to charges under the original power service agreement through June 1, 2001.

Construction Program

Consolidated capital expenditures in 2004 are estimated to be (dollars in millions):

APS	$	426
Pinnacle West Energy		61
SunCor		83
Other (primarily APS Energy Services and Pinnacle West)		11
Total	$	581

Natural Gas Supply

APS and Pinnacle West Energy purchase the majority of their natural gas requirements for their gas-fired plants under contracts with a number of natural gas suppliers. Effective September 1, 2003, APS' and Pinnacle West Energy's natural gas supply is transported pursuant to a firm, contract demand service agreement with El Paso Natural Gas Company. Pursuant to the terms of a comprehensive settlement entered into in 1996, the rates charged for transportation are subject to a 10-year rate moratorium extending through December 31, 2005.

Prior to September 1, 2003, APS' and Pinnacle West Energy's natural gas supply was transported pursuant to a firm, full requirements transportation service agreement. On July 9, 2003, the FERC issued an order that altered the contractual obligations and the rights of parties to the 1996 settlement by requiring all firm, full requirements contract holders to convert to contract demand service agreements effective September 1, 2003. This required conversion has imposed additional limitations on the former full requirements contract holders' ability to nominate firm transportation capacity. In order for APS and Pinnacle West Energy to meet their natural gas supply and capacity requirements, they must make market purchases, which we expect to increase costs by approximately $5 million per year for natural gas supply and by approximately $14 million per year for capacity. APS and Pinnacle West Energy have sought appellate review of the FERC's July 9 order and related issues on the grounds that the FERC decision to abrogate the full requirements contracts is arbitrary and capricious and is not supported by substantial evidence. Arizona Public Service Company and Pinnacle West Energy Corporation v. Federal Energy Regulatory Commission, United States Court of Appeals for the District of Columbia Circuit, No. 03-1209. This petition for review was consolidated with a petition filed by the ACC and other full requirements contract holders. Arizona Corporation Commission et al v. Federal Energy Regulatory Commission, United States Court of Appeals for the District of Columbia Circuit, No. 03-1206. We are continuing to analyze the market to determine the most favorable source and method of meeting our natural gas requirements.

Litigation

We are party to various other claims, legal actions and complaints arising in the ordinary course of business, including but not limited to environmental matters related to the Clean Air Act, Navajo Nation issues and EPA and ADEQ issues. In our opinion, the ultimate resolution of these matters will not have a material adverse effect on our consolidated financial statements, results of operations or liquidity.

12. ASSET RETIREMENT OBLIGATIONS

On January 1, 2003, we adopted SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 provides accounting requirements for the recognition and measurement of liabilities associated with the retirement of tangible long-lived assets. The standard requires that these liabilities be recognized at fair value as incurred and capitalized as part of the related tangible long-lived assets. Accretion of the liability due to the passage of time is an operating expense and the capitalized cost is depreciated over the useful life of the long-lived asset. Prior to January 1, 2003, we accrued asset retirement obligations over the life of the related asset through depreciation expense.

APS has asset retirement obligations for its Palo Verde nuclear facilities and certain other generation, transmission and distribution assets. The Palo Verde asset retirement obligation primarily relates to final plant decommissioning. This obligation is based on the NRC's requirements for disposal of radiated property or plant and agreements APS reached with the ACC for final decommissioning of the plant. The non-nuclear generation asset retirement obligations primarily relate to requirements for removing portions of those plants at the end of the plant life or lease term. Some of APS' transmission and distribution assets have asset retirement obligations because they are subject to right of way and easement agreements that require final removal. These agreements have a history of uninterrupted renewal that APS expects to continue. As a result, APS cannot reasonably estimate the fair value of the asset retirement obligation related to such distribution and transmission assets. The asset retirement obligations associated with our non-regulated assets are immaterial.

On January 1, 2003 and in accordance with SFAS No. 143, APS recorded a liability of $219 million for its asset retirement obligations, including the accretion impacts; a $67 million increase in the carrying amount of the associated assets; and a net reduction of $192 million in accumulated depreciation related primarily to the reversal of previously recorded accumulated decommissioning and other removal costs related to these obligations. Additionally, APS recorded a net regulatory liability of $40 million for the asset retirement obligations related to its regulated assets. This regulatory liability represents the difference between the amount currently being recovered in regulated rates and the amount calculated under SFAS No. 143. APS believes it can recover in regulated rates the transition costs and ongoing current period costs calculated in accordance with SFAS No. 143. The adoption of SFAS No. 143 did not have a material impact on our net income for the year ended December 31, 2003.

APS has reclassified prior year removal costs of approximately $557 million previously included in accumulated depreciation to the liability for asset retirements and removals on our Consolidated Balance Sheets. In 2003, APS reclassified the portion of this liability for which no legal obligation for removal exists to a regulatory liability.

In accordance with SFAS No. 71, APS will continue to accrue for removal costs for its regulated assets, even if there is no legal obligation for removal. At December 31, 2003, regulatory liabilities shown on our Consolidated Balance Sheets included approximately $480 million of estimated future removal costs that are not considered legal obligations.

The following schedule shows the change in our asset retirement obligations during the twelve-month period ended December 31, 2003 (dollars in millions):

Balance at January 1, 2003	$	219
Changes attributable to:		
Liabilities incurred		–
Liabilities settled		–
Accretion expense		15
Estimated cash flow revisions		–
Balance at December 31, 2003	$	234

The following schedule shows the change in our pro forma liability for the years ended December 31, 2002 and 2001, as if we had recorded an asset retirement obligation based on the guidance in SFAS No. 143 (dollars in millions):

Years Ended December 31,		2002		2001
Balance at beginning of year	$	204	$	190
Accretion expense		15		14
Balance at end of year	$	219	$	204

The pro forma effects on net income for 2002 and 2001 are immaterial.

To fund the costs APS expects to incur to decommission Palo Verde, APS established external decommissioning trusts in accordance with NRC regulations. APS invests the trust funds in fixed income and domestic equity securities and classifies them as available for sale.

The following table shows the cost and fair value of APS' nuclear decommissioning trust fund assets which are on the Consolidated Balance Sheets at December 31, 2003 and December 31, 2002 (dollars in millions):

December 31,		2003		2002
Trust fund assets – at cost:				
Fixed income securities	$	124	$	113
Domestic stock		74		68
Total	$	198	$	181
Trust fund assets – at fair value:				
Fixed income securities	$	140	$	117
Domestic stock		101		77
Total	$	241	$	194

13. SELECTED QUARTERLY FINANCIAL DATA (UNAUDITED)

Consolidated quarterly financial information for 2003 and 2002 is as follows (dollars in thousands, except per share amounts):

	Operating Revenues as Previously Disclosed (a)	Reclassification Adjustment (b)	Operating Revenues	Operating Income	Income from Continuing Operations	Net Income (d)
2003 quarter ended:						
March 31	$ 603,962	$ 51,319	$ 552,643	$ 69,255	$ 20,153	$ 25,298
June 30	757,483	74,181	683,302	132,482	54,889	56,142
September 30	946,570	98,867	847,703	198,850	109,538	110,048
December 31	734,204	–	734,204	81,466	45,996	49,091
Total		$ 224,367	$ 2,617,852	$ 482,053	$ 230,576	$ 240,579

	Operating Revenues as Previously Disclosed (a)	Reclassification Adjustment (b)(c)	Operating Revenues	Operating Income	Income (Loss) from Continuing Operations	Net Income (Loss) (d)
2002 quarter ended:						
March 31	$ 499,844	$ 16,365	$ 483,479	$ 118,736	$ 53,251	$ 53,757
June 30	593,516	18,962	574,554	155,832	68,603	75,365
September 30	671,390	103,450	767,940	212,491	100,713	100,916
December 31 (f)	644,436	30,121	614,315	13,875	(16,569)	(80,630)
Total		$ 168,898	$ 2,440,288	$ 500,934	$ 206,198	$ 149,408

(a) Operating revenues previously disclosed in the March 31, 2003, June 30, 2003 and September 30, 2003 Quarterly Reports on Form 10-Q, except for the fourth quarter ended December 31, 2003, which was disclosed in a Pinnacle West Form 8-K dated January 29, 2004 and the fourth quarter ended December 31, 2002, which was disclosed in a Pinnacle West Form 8-K dated February 4, 2003.

(b) Reclassification adjustment of $224 million in 2003 and $162 million in 2002 related to the adoption of EITF 03-11 (see Note 18).

(c) Reclassification adjustment of $7 million in the fourth quarter of 2002 related to discontinued operations at SunCor (see Note 22).

(d) Includes income from discontinued operations at SunCor (see Note 22).

(e) Includes a $66 million after-tax charge for the cumulative effect of a change in accounting for trading activities (see Note 18).

(f) The fourth quarter of 2002 included pretax losses of $38 million related to our investment in NAC, a $40 million pretax write-off related to the cancellation of Redhawk Units 3 and 4 and pretax severance costs of approximately $11 million.

Income From Continuing Operations – EPS:

	2003 Basic	2003 Diluted	2002 Basic	2002 Diluted
Quarter ended:				
March 31	$ 0.22	$ 0.22	$ 0.63	$ 0.63
June 30	0.60	0.60	0.81	0.81
September 30	1.20	1.20	1.19	1.19
December 31	0.50	0.50	(0.19)	(0.19)

Net Income – EPS:

	2003 Basic	2003 Diluted	2002 Basic	2002 Diluted
Quarter ended:				
March 31	$ 0.28	$ 0.26	$ 0.63	$ 0.63
June 30	0.62	0.61	0.89	0.89
September 30	1.21	1.20	0.19	1.19
December 31	0.54	0.54	(0.95)	(0.95)

14. FAIR VALUE OF FINANCIAL INSTRUMENTS

We believe that the carrying amounts of our cash equivalents are reasonable estimates of their fair values at December 31, 2003 and 2002 due to their short maturities.

We hold investments in fixed income and domestic equity securities for purposes other than trading. The December 31, 2003 and 2002 fair values of such investments, which we determine by using quoted market prices, approximate their carrying amount. For further information, see disclosure of cost and fair value of APS' nuclear decommissioning trust fund assets in Note 12.

On December 31, 2003, the carrying value of our long-term debt (excluding capitalized lease obligations) was $3.32 billion, with an estimated fair value of $3.46 billion. The carrying value of our long-term debt (excluding capitalized lease obligations) was $3.00 billion on December 31, 2002, with an estimated fair value of $3.21 billion. The fair value estimates are based on quoted market prices of the same or similar issues.

15. EARNINGS PER SHARE

The following table presents earnings per weighted average common share outstanding for the years ended December 31, 2003, 2002 and 2001:

	2003	2002	2001
Basic earnings per share:			
Income from continuing operations	$ 2.53	$ 2.43	$ 3.86
Income from discontinued operations	0.11	0.10	–
Cumulative effect of change in accounting	–	(0.77)	(0.18)
Earnings per share – basic	$ 2.64	$ 1.76	$ 3.68
Diluted earnings per share:			
Income from continuing operations	$ 2.52	$ 2.43	$ 3.85
Income from discontinued operations	0.11	0.10	–
Cumulative effect of change in accounting	–	(0.77)	(0.17)
Earnings per share – diluted	$ 2.63	$ 1.76	$ 3.68

Dilutive stock options increased average common shares outstanding by approximately 140,000 shares in 2003, 61,000 shares in 2002 and 212,000 shares in 2001. Total average common shares outstanding for the purposes of calculating diluted earnings per share were 91,405,134 shares in 2003, 84,963,921 shares in 2002 and 84,930,140 shares in 2001.

Options to purchase 2,291,646 shares of common stock were outstanding at December 31, 2003 but were not included in the computation of diluted earnings per share because the options' exercise price was greater than the average market price of the common shares. Options to purchase shares of common stock that were not included in the computation of diluted earnings per share were 1,629,956 at December 31, 2002 and 212,562 at December 31, 2001.

16. STOCK-BASED COMPENSATION

Pinnacle West offers stock-based compensation plans for officers and key employees of the Company and our subsidiaries.

In May 2002, shareholders approved the 2002 Long-Term Incentive Plan (2002 plan), which allows Pinnacle West to grant performance shares, stock ownership incentive awards and non-qualified and performance-accelerated stock options to key employees. The Company has reserved 6 million shares of common stock for issuance under the 2002 plan. No more than 1.8 million shares may be issued in relation to performance share awards and stock ownership incentive awards. The plan also provides for the granting of new non-qualified stock options at a price per share not less than the fair market value of the common stock at the time of grant.

The stock options vest over three years, unless certain performance criteria are met, which can accelerate the vesting period. The term of the option cannot be longer than 10 years and the option cannot be repriced during its term.

The 1994 plan and the 1985 plan each include outstanding options but no new options will be granted under either plan. Options vest one-third of the grant per year beginning one year after the date the option is granted and expire ten years from the date of the grant. The 1994 plan also provided for the granting of any combination of shares of restricted stock, stock appreciation rights or dividend equivalents. Following the approval of the 2002 plan, no further grants have been made under the 1994 plan, except for awards for the annual award of up to 20,000 shares of stock to satisfy stock award obligations under employment contracts to certain executives.

In the third quarter of 2002, we began applying the fair value method of accounting for stock-based compensation, as provided for in SFAS No. 123. The fair value method of accounting is the preferred method. In accordance with the transition requirements of SFAS No. 123, we applied the fair value method prospectively, beginning with 2002 stock grants. In prior years, we recognized stock compensation expense based on the intrinsic value method allowed in APB No. 25. We recorded approximately $2.1 million in stock option expense before income taxes in our Consolidated Statements of Income in 2003 and approximately $0.5 million in 2002. This amount may not be reflective of the stock option expense we will record in future years because stock options typically vest over several years and additional grants are generally made each year.

In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure." The standard amends SFAS No. 123 to provide alternative methods of transition for a voluntary change to the fair value method of accounting for stock-based compensation. The standard also amends the disclosure requirements of SFAS No. 123. SFAS No. 148 is effective for fiscal years ending after December 15, 2002. We adopted the disclosure requirements in 2002. See Note 1 for our pro forma disclosures on stock-based compensation and our weighted-average assumptions used to calculate the fair value of our stock options.

Total stock-based compensation cost, including stock option cost, was $6 million in 2003, $5 million in 2002 and $3 million in 2001.

The following table is a summary of the status of our stock option plans as of December 31, 2003, 2002 and 2001 and changes during the years ending on those dates:

	2003 Shares	2003 Weighted Average Exercise Price	2002 Shares	2002 Weighted Average Exercise Price	2001 Shares	2001 Weighted Average Exercise Price
Outstanding at beginning of year	2,185,129	$ 39.96	1,832,725	$ 39.52	1,569,171	$ 37.55
Granted	621,875	32.29	603,900	38.37	444,200	42.55
Exercised	(62,366)	26.09	(163,381)	28.25	(162,229)	28.53
Forfeited	(46,392)	37.61	(88,115)	41.54	(18,417)	41.67
Outstanding at end of year	2,696,246	38.56	2,185,129	39.96	1,832,725	39.52
Options exercisable at year-end	1,787,622	40.35	1,155,357	39.66	926,315	37.41
Weighted average fair value of options granted during the year		$ 7.37		$ 6.16		$ 8.84

The following table summarizes information about our stock options at December 31, 2003:

Exercise Prices Per Share	Options Outstanding	Weighted-Average Exercise Price	Weighted Average Remaining Contract Life (Years)	Options Exercisable	Weighted-Average Exercise Price
$18.71-23.39	10,584	$ 19.00	0.8	10,584	$ 19.00
23.39-28.07	48,417	27.40	2.3	48,417	27.40
28.07-32.75	647,400	32.23	8.7	49,625	31.50
32.75-37.42	220,994	34.70	5.4	220,994	34.70
37.42-42.10	759,333	38.86	6.7	579,854	38.95
42.10-46.78	1,011,518	43.96	6.1	878,148	44.17
	2,698,246			1,787,622	

The following table is a summary of the amount and weighted-average grant date fair value of stock compensation awards granted, other than options, during the years ended December 31, 2003, 2002 and 2001:

	2003 Shares	2003 Grant Price	2002 Shares	2002 Grant Price	2001 Shares	2001 Grant Price
Restricted stock	4,000	$ 32.20(a)	6,000	$ 38.84(a)	95,450	$ 42.84(a)
Performance share awards	119,085	32.29(b)	115,975	38.37(b)	–	–

(a) Restricted stock priced at the average of the high and low market price for the grant date.
(b) Performance shares priced at the closing market price for the grant date

17. BUSINESS SEGMENTS

We have three principal business segments (determined by products, services and the regulatory environment):

- our regulated electricity segment, which consists of traditional regulated retail and wholesale electricity businesses and related activities, and includes electricity generation, transmission and distribution;
- our marketing and trading segment, which consists of our competitive energy business activities, including wholesale marketing and trading and APS Energy Services' commodity-related energy services. In early 2003, we moved our marketing and trading activities to APS from Pinnacle West (existing wholesale contracts remained at Pinnacle West) as a result of the ACC's Track A Order prohibiting the previously required transfer of APS' generating assets to Pinnacle West Energy; and
- our real estate segment, which consists of SunCor's real estate development and investment activities.

The amounts in our other segment include activity principally related to El Dorado's investment in NAC, as well as the parent company and other subsidiaries. See Note 18 for information about reclassifications related to the adoption of EITF 03-11. Financial data for the years ended December 31, 2003, 2002 and 2001 by business segments is provided as follows (dollars in millions):

	Business Segments for the Year Ended December 31, 2003				
	Regulated Electricity	Marketing and Trading	Real Estate	Other (principally NAC)	Total
Operating revenues	$ 1,978	$ 392	$ 362	$ 86	$ 2,818
Purchased power and fuel costs	517	345	–	–	862
Other operating expenses	625	34	306	71	1,036
Operating margin	836	13	56	15	920
Depreciation and amortization	428	1	6	3	438
Interest expense	172	–	2	1	175
Other expense/(income)	(4)	–	(25)	–	(29)
Pretax margin	240	12	73	11	336
Income taxes	70	3	28	4	105
Income from continuing operations	170	9	45	7	231
Income from discontinued operations – net of income taxes of $6 (see Note 22)	–	–	10	–	10
Net income	$ 170	$ 9	$ 55	$ 7	$ 241
Total assets	$ 8,761	$ 324	$ 424	$ 27	$ 9,536
Capital expenditures	$ 686	$ 9	$ 72	$ –	$ 767

	Business Segments for the Year Ended December 31, 2002				
	Regulated Electricity	Marketing and Trading	Real Estate	Other (principally NAC)	Total
Operating revenues	$ 1,890	$ 287	$ 201	$ 62	$ 2,440
Purchased power and fuel costs	377	155	–	–	532
Other operating expenses	659	34	185	105	983
Operating margin	854	98	16	(43)	925
Depreciation and amortization	416	2	4	2	424
Interest expense	141	–	2	1	144
Other expense/(income)	19	–	(7)	7	19
Pretax margin	278	96	17	(53)	338
Income taxes	108	38	7	(21)	132
Income (loss) from continuing operations	170	58	10	(32)	206
Income from discontinued operations – net of income taxes of $6 (see Note 22)	–	–	9	–	9
Cumulative effect of change in accounting for trading activities – net of income taxes of $43	–	(66)	–	–	(66)
Net income (loss)	$ 170	$ (8)	$ 19	$ (32)	$ 149
Total assets	$ 8,185	$ 414	$ 504	$ 36	$ 9,139
Capital expenditures	$ 893	$ 19	$ 72	$ –	$ 984

	Business Segments for the Year Ended December 31, 2001				
	Regulated Electricity	Marketing and Trading	Real Estate	Other	Total
Operating revenues	$ 1,984	$ 470	$ 169	$ 12	$ 2,635
Purchased power and fuel costs	583	153	–	–	736
Other operating expenses	598	33	154	11	796
Operating margin	803	284	15	1	1,103
Depreciation and amortization	423	1	4	–	428
Interest expense	125	–	3	–	128
Other expense/(income)	4	–	3	–	7
Pretax margin	251	283	5	1	540
Income taxes	99	112	2	–	213
Income before accounting change	152	171	3	1	327
Cumulative effect of change in accounting for derivatives – net of income taxes of $10	(15)	–	–	–	(15)
Net income	$ 137	$ 171	$ 3	$ 1	$ 312
Capital expenditures	$ 1,004	$ 23	$ 80	$ 22	$ 1,129

18. DERIVATIVE AND ENERGY TRADING ACCOUNTING

We are exposed to the impact of market fluctuations in the commodity price and transportation costs of electricity, natural gas, coal and emissions allowances. We manage risks associated with these market fluctuations by utilizing various commodity instruments that qualify as derivatives, including exchange-traded futures and options and over-the-counter forwards, options and swaps. As part of our overall risk management program, we use such instruments to hedge purchases and sales of electricity, fuels, and emissions allowances and credits. The changes in market value of such contracts have a high correlation to price changes in the hedged commodities. In addition, subject to specified risk parameters monitored by the ERMC, we engage in marketing and trading activities intended to profit from market price movements.

Effective January 1, 2001, we adopted SFAS No. 133. SFAS No. 133 requires that entities recognize all derivatives as either assets or liabilities on the balance sheet and measure those instruments at fair value. Changes in the fair value of derivative instruments are either recognized periodically in income or, if hedge criteria is met, in common stock equity (as a component of other comprehensive income (loss)). We use cash flow hedges to limit our exposure to cash flow variability on forecasted transactions. Hedge effectiveness is related to the degree to which the derivative contract and the hedged item are correlated. It is measured based on the relative changes in fair value between the derivative contract and the hedged item over time. We exclude the time value of certain options from our assessment of hedge effectiveness. Any change in the fair value resulting from ineffectiveness, or the amount by which the derivative contract and the hedged commodity are not directly correlated, is recognized immediately in net income.

In 2001, we recorded a $15 million after-tax charge in net income and a $72 million after-tax credit in common stock equity (as a component of other comprehensive income (loss)), both as cumulative effects of a change in accounting for derivatives. The charge primarily resulted from electricity option contracts. The credit resulted from unrealized gains on cash flow hedges.

During 2002, the EITF discussed EITF 02-3 and reached a consensus on certain issues. EITF 02-3 rescinded EITF 98-10 and was effective October 25, 2002 for any new contracts, and on January 1, 2003 for existing contracts, with early adoption permitted. We adopted the EITF 02-3 guidance for all contracts in the fourth quarter of 2002. We recorded a $66 million after-tax charge in net income as a cumulative effect adjustment for the previously recorded accumulated unrealized mark-to-market on energy trading contracts that did not meet the accounting definition of a derivative. Our energy trading contracts that are derivatives are accounted for at fair value under SFAS No. 133. Energy trading contracts that do not meet the definition of a derivative are accounted for on an accrual basis with the associated revenues and costs recorded at the time the contracted commodities are delivered or received. Additionally, all gains and losses (realized and unrealized) on energy trading contracts that qualify as derivatives are included in marketing and trading segment revenues on the Consolidated Statements of Income on a net basis. Derivative instruments used for non-trading activities are accounted for in accordance with SFAS No. 133.

Both non-trading and trading derivatives are classified as assets and liabilities from risk management and trading activities in the Consolidated Balance Sheets. For non-trading derivative instruments that qualify for cash flow hedge accounting treatment, changes in the fair value of the effective portion are recognized in common stock equity (as a component of other comprehensive income (loss)). Non-trading derivatives, or any portion thereof, that are not effective hedges are adjusted to fair value through income. Gains and losses related to non-trading derivatives that qualify as cash flow hedges of expected transactions are recognized in revenue or purchased power and fuel expense as an offset to the related item being hedged when the underlying hedged physical transaction impacts earnings. If it becomes probable that a forecasted transaction will not occur, we discontinue the use of hedge accounting and recognize in income the unrealized gains and losses

that were previously recorded in other comprehensive income (loss). In the event a non-trading derivative is terminated or settled, the unrealized gains and losses remain in other comprehensive income (loss), and are recognized in income when the underlying transaction impacts earnings. Derivative commodity contracts for the physical delivery of purchase and sale quantities transacted in the normal course of business are exempt from the requirements of SFAS No. 133 under the normal purchase and sales exception and are not reflected on the balance sheet at fair value. Certain of our non-trading electricity purchase and sales agreements qualify as normal purchases and sales and are exempted from recognition in the financial statements until the electricity is delivered. Derivatives associated with trading activities are adjusted to fair value through income.

EITF 02-3 requires that derivatives held for trading purposes, whether settled financially or physically, be reported in the income statement on a net basis. Previous guidance under EITF 98-10 permitted physically-settled energy trading contracts to be reported either gross or net in the income statement. Beginning in the third quarter of 2002, we netted all of our energy trading activities on the Consolidated Statements of Income and restated prior year amounts for all periods presented. Reclassification of such trading activity to a net basis of reporting resulted in reductions in both revenues and purchased power and fuel costs, but did not have any impact on our financial condition, net income or cash flows.

We adopted EITF 03-11, "Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not 'Held for Trading Purposes' As Defined in Issue No. 02-3," effective October 1, 2003. EITF 03-11 provided guidance on whether realized gains and losses on physically settled derivative contracts not held for trading purposes should be reported on a net or gross basis and concluded such classification is a matter of judgment that depends on the relevant facts and circumstances. In the electricity business, some contracts to purchase energy are netted against other contracts to sell energy. This is called "book-out" and usually occurs in contracts that have the same terms (quantities and delivery points) and for which power does not flow. We netted these book-outs reducing both revenues and purchased power and fuel costs in 2003, 2002 and 2001, but this did not impact our financial condition, net income or cash flows. Following are the net reclassifications to our previously reported amounts (dollars in thousands):

Year Ended December 31,	2003	2002	2001
Regulated Electricity	$ 40,069	$ 122,632	$ 577,783
Marketing and Trading	184,298	39,052	181,447
Total	$ 224,367	$ 161,684	$ 759,230

In November 2003, the FASB revised its derivative guidance in DIG Issue No. C15, "Normal Purchases and Normal Sales Exception for Option-Type Contracts and Forward Contracts in Electricity." Effective January 1, 2004, the new guidance changes the criteria for the normal purchases and sales scope exception for electricity contracts. We do not expect this guidance to have a material impact on our financial statements.

In April 2003, the FASB issued SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." This statement amends and clarifies financial accounting and reporting for derivative instruments and for hedging activities under SFAS No. 133. The provisions of SFAS No. 149 that relate to previously issued SFAS No. 133 derivatives implementation guidance should continue to be applied in accordance with the effective dates of the original implementation guidance. In general, other provisions are applied prospectively to contracts entered into or modified after June 30, 2003, and for hedging relationships designated after June 30, 2003. The impact of this standard was immaterial to our financial statements.

The changes in the fair value of our hedged positions included in the Consolidated Statements of Income for the years ended December 31, 2003 and 2002 are comprised of the following (dollars in thousands):

Year Ended December 31,	2003	2002
Gains on the ineffective portion of derivatives qualifying for hedge accounting	$ 6,237	$ 13,682
Gains/(losses) from the change in options' time value excluded from measurement of effectiveness	181	(2,484)
Losses from the discontinuance of cash flow hedges	–	(8,820)

As of December 31, 2003, the maximum length of time over which we are hedging our exposure to the variability in future cash flows for forecasted transactions is approximately five years. During the year ending December 31, 2004, we estimate that a net gain of $8 million before income taxes will be reclassified from accumulated other comprehensive loss as an offset to the effect on earnings of market price changes for the related hedged transactions.

Our assets and liabilities from risk management and trading activities are presented in two categories, consistent with our business segments:

- Regulated Electricity – non-trading derivative instruments that hedge our purchases and sales of electricity and fuel for APS' Native Load requirements of our regulated electricity business segment; and
- Marketing and Trading – both non-trading and trading derivative instruments of our competitive business segment.

The following table summarizes our assets and liabilities from risk management and trading activities at December 31, 2003 and 2002 (dollars in thousands):

December 31, 2003	Current Assets	Investments	Current Liabilities	Other Liabilities	Net Asset/ (Liability)
Regulated Electricity:					
Mark-to-Market	$ 44,079	$ 5,900	$ (47,266)	$ (3,028)	$ (317)
Options	–	12,101	–	–	12,101
Marketing and Trading:					
Mark-to-Market	53,551	116,363	(37,023)	(63,398)	69,493
Emission allowances – at cost	–	4,582	(8,464)	(16,304)	(20,186)
Total	$ 97,630	$ 138,946	$ (92,755)	$ (82,730)	$ 61,091

December 31, 2002	Current Assets	Investments	Current Liabilities	Other Liabilities	Net Asset/ (Liability)
Regulated Electricity:					
Mark-to-Market	$ 41,522	$ 6,971	$ (60,819)	$ (36,678)	$ (49,004)
Options	–	24,651	–	–	24,651
Marketing and Trading:					
Mark-to-Market	61,142	121,189	(50,510)	(74,841)	56,980
Emission allowances – at cost	–	38,943	–	(36,381)	2,562
Total	$ 102,664	$ 191,754	$ (111,329)	$ (147,900)	$ 35,189

Cash or collateral may be required to serve as collateral against our open positions on certain energy-related contracts. Collateral provided to counterparties is $1 million at December 31, 2003 and $5 million at December 31, 2002, and is included in investments and other assets on the Consolidated Balance Sheet. Collateral provided to us by counterparties is $12 million at December 31, 2003 and $22 million at December 31, 2002, and is included in other deferred credits on the Consolidated Balance Sheet.

Credit Risk

We are exposed to losses in the event of nonperformance or nonpayment by counterparties. We have risk management and trading contracts with many counterparties, including two counterparties for which a worst case exposure represents approximately 37% of our $237 million of risk management and trading assets as of December 31, 2003. Our risk management process assesses and monitors the financial exposure of those and all other counterparties. Despite the fact that the great majority of trading counterparties are rated as investment grade by the credit rating agencies, including the counterparties noted above, there is still a possibility that one or more of these companies could default, resulting in a material impact on consolidated earnings for a given period. Counterparties in the portfolio consist principally of major energy companies, municipalities and local distribution companies. We maintain credit policies that we believe minimize overall credit risk to within acceptable limits. Determination of the credit quality of our counterparties is based upon a number of factors, including credit ratings and our evaluation of their financial condition.

In many contracts, we employ collateral requirements and standardized agreements that allow for the netting of positive and negative exposures associated with a single counterparty. Valuation adjustments are established representing our estimated credit losses on our overall exposure to counterparties. See Note 1 "Mark-to-Market Accounting" for a discussion of our credit valuation adjustment policy.

19. OTHER INCOME AND OTHER EXPENSE

The following table provides detail of other income and other expense for the years ended December 31, 2003, 2002 and 2001 (dollars in thousands):

Year Ended December 31,	2003	2002	2001
Other income:			
SunCor joint venture earnings (a)	$ 24,740	$ 7,355	$ 3,687
Interest income	4,412	4,332	6,763
Investment gains	3,649	–	–
Environmental insurance recovery	–	–	12,349
Miscellaneous	2,762	3,223	3,617
Total other income	$ 35,563	$ 14,910	$ 26,416
Other expense:			
Non-operating costs (b)	$ (16,461)	$ (19,430)	$ (16,607)
Investment losses (c)	–	(10,439)	(5,126)
Non-operating costs – SunCor	–	–	(7,000)
Miscellaneous	(4,093)	(3,786)	(4,644)
Total other expense	$ (20,574)	$ (33,655)	$ (33,577)

(a) Primarily related to the sale at SunCor of a land interest and profit participation agreement in the fourth quarter of 2003 for $13 million. In 2002, SunCor received $2.5 million for the profit participation.

(b) As defined by the FERC, includes below-the-line non-operating utility costs (primarily community relations).

(c) Primarily related to El Dorado's investment losses in NAC prior to consolidation in the third quarter of 2002.

20. VARIABLE INTEREST ENTITIES

In 2003, we adopted FIN No. 46R, "Consolidation of Variable Interest Entities," as it applies to special-purpose entities. FIN No. 46R requires that we consolidate a VIE if we have a majority of the risk of loss from the VIE's activities or we are entitled to receive a majority of the VIE's residual returns or both. A VIE is a corporation, partnership, trust or any other legal structure that either does not have equity investors with voting rights or has equity investors that do not provide sufficient financial resources for the entity to support its activities. In 1986, APS entered into agreements with three separate SPE lessors in order to sell and lease back interests in Palo Verde Unit 2. The leases are accounted for as operating leases in accordance with GAAP. See Note 9 for further information about the sale leaseback transactions. Based on our assessment of FIN No. 46R, we are not required to consolidate the Palo Verde VIEs. Certain provisions of FIN No. 46R have a future effective date. We do not expect these provisions to have a material impact on our financial statements.

APS is exposed to losses under the Palo Verde sale leaseback agreements upon the occurrence of certain events that APS does not consider to be reasonably likely to occur. Under certain circumstances (for example, the NRC issuing specified violation orders with respect to Palo Verde or the occurrence of specified nuclear events), APS would be required to assume the debt associated with the transactions, make specified payments to the equity participants, and take title to the leased Unit 2 interests, which, if appropriate, may be required to be written down in value. If such an event had occurred as of December 31, 2003, APS would have been required to assume approximately $268 million of debt and pay the equity participants approximately $200 million.

21. GUARANTEES

On January 1, 2003, we adopted FIN No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." FIN No. 45 elaborates on the disclosures to be made by a guarantor in its financial statements about its obligations under certain guarantees. It also clarifies that a guarantor is required to recognize, at inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. The disclosure provisions were effective for the year ended December 31, 2002. The initial recognition and measurement provisions of FIN No. 45 were effective on a prospective basis to guarantees issued or modified after December 31, 2002.

We have issued parental guarantees and letters of credit and obtained surety bonds on behalf of our unregulated subsidiaries. Our parental guarantees related to Pinnacle West Energy consist of equipment and performance guarantees related to our generation construction program, transmission service guarantees for West Phoenix Units 4 and 5 and long-term service agreement guarantees for new power plants. Our credit support instruments enable APS Energy Services to offer commodity energy and energy-related products and enable El Dorado to support the activities of NAC. Non-performance or payment under the original contract by our unregulated subsidiaries would require us to perform under the guarantee or surety bond. No liability is currently recorded on the Consolidated Balance Sheets related to Pinnacle West's guarantees on behalf of its subsidiaries. Our guarantees have no recourse (except NAC) or collateral provisions to allow us to recover amounts paid under the guarantee. The amounts and approximate terms of our guarantees and surety bonds for each subsidiary at December 31, 2003 are as follows (dollars in millions):

	Guarantees		Surety Bonds	
	Amount	Term (in years)	Amount	Term (in years)
Parental:				
Pinnacle West Energy	$ 86	1 to 2	$ –	–
APS Energy Services	16	1 to 2	35	2
El Dorado (NAC)	40	1 to 3	–	–
Total	$ 142		$ 35	

At December 31, 2003, we had entered into approximately $41 million of letters of credit which support various construction agreements. These letters of credit expire in 2004 and 2005. We intend to provide from either existing or new facilities for the extension, renewal or substitution of the letters of credit to the extent required. At December 31, 2003, Pinnacle West has approximately $4 million of letters of credit related to workers' compensation expiring in 2004.

APS has entered into various agreements that require letters of credit for financial assurance purposes. At December 31, 2003, approximately $200 million of letters of credit were outstanding to support existing pollution control bonds of approximately $200 million. The letters of credit are available to fund the payment of principal and interest of such debt obligations. These letters of credit have expiration dates in 2004 and 2005. APS has also entered into approximately $109 million of letters of credit to support certain equity lessors in the Palo Verde sale leaseback transactions (see Note 9 for further details on the Palo Verde sale leaseback transactions). These letters of credit expire in 2005. Additionally, APS has approximately $5 million of letters of credit related to counterparty collateral requirements expiring in 2004. APS intends to provide from either existing or new facilities for the extension, renewal or substitution of the letters of credit to the extent required.

We provide indemnifications relating to liabilities arising from or related to certain of our agreements. APS has provided indemnifications to the equity participants and other parties in the Palo Verde sale leaseback transactions with respect to certain tax matters. Generally, a maximum obligation is not explicitly stated in the indemnification and therefore, the overall maximum amount of the obligation under such indemnifications cannot be reasonably estimated. Based on historical experience and evaluation of the specific indemnities, we do not believe that any material loss related to such indemnifications is likely and therefore no related liability has been recorded.

22. REAL ESTATE ACTIVITIES – DISCONTINUED OPERATIONS

Certain components of SunCor's real estate sales activities, which are included in the real estate segment, are required to be reported as discontinued operations on our Consolidated Statements of Income in accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." Among other guidance, SFAS No. 144 prescribes accounting for discontinued operations and defines certain activities as discontinued operations. We adopted SFAS No. 144 effective January 1, 2002 and determined that activities that would have required discontinued operations reporting in 2002 and 2001 were immaterial.

In 2003, SunCor sold its water utility company, which resulted in an after-tax gain of $6 million ($14 million pretax). The amounts of the gain on the sale and operating income of the water utility company in 2003 and 2002 are classified as discontinued operations on our Consolidated Statements of Income. The amounts related to 2001 were immaterial for reclassification.

In the second quarter of 2002, SunCor sold a retail center, but maintained a continuing involvement through a management contract. In the first quarter of 2003, this management contract was canceled. As a result, the after-tax gain of $6 million ($10 million pre-tax) recorded in operations in 2002 related to this property was reclassified as discontinued operations on our Consolidated Statements of Income. The income from discontinued operations in the year ended December 31, 2002 primarily reflects this sale. The amounts related to 2001 were immaterial for reclassification.

In the fourth quarter of 2003, SunCor sold a retail center, which resulted in an after-tax gain of $2 million ($3 million pretax). The gain on the sale and the operating income related to this property in 2003 are classified as discontinued operations on our Consolidated Statements of Income. There were no prior-year operations related to this retail center. The amounts related to 2001 were immaterial for reclassification.

The following table provides SunCor's revenue and income before income taxes related to properties classified as discontinued operations on our consolidated statements of income for the years ended December 31, 2003 and 2002 (dollars in thousands):

	2003	2002
Revenue	$ 70,580	$ 35,307
Income before taxes	$ 16,532	$ 14,827

The following tables provide the amounts related to properties of discontinued operations which were reclassified to assets and liabilities held for sale on the Consolidated Balance Sheets at December 31, 2003 and 2002 (dollars in thousands):

	2003	2002
Real estate investments – net	$ –	$ 39,849
Other	–	2,490
Real estate assets held for sale	$ –	$ 42,339

	2003	2002
Customer deposits	$ –	$ 13,648
Long-term debt less current maturities	–	12,454
Other	–	2,753
Real estate liabilities held for sale	$ –	$ 28,855

See Note 17 for information related to the real estate segment.

Board of Directors













1_PAMELA GRANT, (65) 1980* Civic Leader COMMITTEES: *Human Resources, Chairman; Audit; Corporate Governance*

2_MARTHA O. HESSE, (61) 1991 Former CEO, Hesse Gas Company COMMITTEES: *Audit, Chairman; Finance and Operating; Corporate Governance*

3_THE REV. BILL JAMIESON, JR., (60) 1991 President, Institute for Servant Leadership of Asheville, North Carolina COMMITTEES: *Human Resources; Corporate Governance*

4_ROY A. HERBERGER, JR., (61) 1992 President, Thunderbird, The American Graduate School of International Management COMMITTEES: *Finance and Operating, Chairman; Human Resources; Corporate Governance*

5_ROBERT G. MATLOCK, (70) 1993 Management Consultant, R.G. Matlock & Associates, Inc. COMMITTEES: *Human Resources; Corporate Governance*

6_WILLIAM J. POST, (53) 1994 Chairman of the Board & Chief Executive Officer COMMITTEE: *Finance and Operating*

7_HUMBERTO S. LOPEZ, (58) 1995 President, HSL Properties, Inc. COMMITTEES. *Audit; Corporate Governance*

8_MICHAEL L. GALLAGHER, (59) 1997 Chairman Emeritus, Gallagher & Kennedy, P.A. COMMITTEES: *Human Resources; Corporate Governance, Chairman*

9_BRUCE J. NORDSTROM, (54) 1997 Certified Public Accountant, Nordstrom and Associates, P.C. COMMITTEES: *Audit; Corporate Governance*

10_JACK E. DAVIS, (57) 1998 President & Chief Operating Officer COMMITTEE: *Finance and Operating*

11_WILLIAM L. STEWART, (60) 1998 COMMITTEE: *Finance and Operating*

12_EDDIE BASHA, (66) 1999 Chairman of the Board, Bashas' COMMITTEES: *Audit; Corporate Governance*

13_KATHRYN L. MUNRO, (55) 1999 Principal, BridgeWest L.L.C. COMMITTEES: *Finance and Operating; Corporate Governance*

* The year in which the individual first joined the Board of a Pinnacle West company.

Officers

PINNACLE WEST

William J. Post (53) 1973*
Chairman of the Board
& Chief Executive Officer

Jack E. Davis (57) 1973
President
& Chief Operating Officer

Donald E. Brandt (49) 2002
Executive Vice President
& Chief Financial Officer

Robert S. Aiken (47) 1986
Vice President, Federal Affairs

Barbara M. Gomez (49) 1978
Vice President & Treasurer

Nancy C. Loftin (50) 1985
Vice President, General Counsel
& Secretary

Martin L. Shultz (59) 1979
Vice President,
Government Affairs

ARIZONA PUBLIC SERVICE

William J. Post
Chairman of the Board

Jack E. Davis
President
& Chief Executive Officer

Donald E. Brandt
Executive Vice President
& Chief Financial Officer

Armando B. Flores (60) 1991
Executive Vice President,
Corporate Business Services

James M. Levine (54) 1989
Executive Vice President,
Generation

Steven M. Wheeler (55) 2001
Executive Vice President,
Customer Service & Regulation

Gregg R. Overbeck (57) 1990
Senior Vice President,
Nuclear Generation

Jan H. Bennett (56) 1967
Vice President,
Customer Service

Ajit P. Bhatti (58) 1973
Vice President,
Resource Planning

Dennis L. Brown (53) 1973
Vice President
& Chief Information Officer

John R. Denman (61) 1964
Vice President,
Fossil Generation

Edward Z. Fox (50) 1995
Vice President,
Communications,
Environment & Safety

Chris N. Froggatt (46) 1986
Vice President & Controller

Barbara M. Gomez
Vice President & Treasurer

David A. Hansen (44) 1980
Vice President,
Power Marketing & Trading

Nancy C. Loftin
Vice President, General
Counsel & Secretary

David Mauldin (54) 1990
Vice President,
Nuclear Engineering

Donald G. Robinson (50) 1978
Vice President, Planning

PINNACLE WEST ENERGY

James M. Levine
President
& Chief Executive Officer

Donald E. Brandt
Chief Financial Officer

Ajoy K. Banerjee (58) 1999
Vice President,
Construction & Operations

Warren C. Kotzmann (54) 1989
Vice President, Business
& Corporate Services

SUNCOR DEVELOPMENT

William J. Post
Chairman of the Board

John C. Ogden (58) 1972
President
& Chief Executive Officer

Geoffrey L. Appleyard (50) 1987
Vice President
& Chief Financial Officer

Duane S. Black (51) 1989
Vice President
& Chief Operating Officer

Jay T. Ellingson (55) 1992
Vice President,
Development – Palm Valley

Steven Gervais (48) 1987
Vice President
& General Counsel

Margaret E. Kirch (54) 1988
Vice President
Commercial Development

Thomas A. Patrick (50) 1995
Vice President, Golf Operations

APS ENERGY SERVICES

Vicki G. Sandler (47) 1982
President, APS Energy Services

EL DORADO INVESTMENT

William J. Post
Chairman of the Board,
President
& Chief Executive Officer

* The year in which the individual was first employed within the Pinnacle West group of companies.

Shareholder Information

CORPORATE HEADQUARTERS
400 North 5th Street
P.O. Box 53999
Phoenix, Arizona 85004

Main telephone number: (602) 250-1000

ANNUAL MEETING OF SHAREHOLDERS
Wednesday, May 19, 2004
10:30 a.m.
The Herberger Theater Center
222 East Monroe Street
Phoenix, Arizona 85004

STOCK LISTING
Ticker symbol: PNW on New York Stock Exchange and Pacific Stock Exchange
Newspaper financial listings: PinWst

FORM 10-K
Pinnacle West's Annual Report to the Securities and Exchange Commission on Form 10-K will be available (after March 15, 2004) to shareholders upon written request, without charge.
Write: Office of the Secretary.

INVESTORS ADVANTAGE PLAN
Pinnacle West offers a direct stock purchase plan. Any interested investor may purchase Pinnacle West common stock through the Investors Advantage Plan. Features of the Plan include a variety of options for reinvesting dividends, direct deposit of cash dividends, automatic monthly investment, certificate safekeeping, reduced brokerage commissions and more. An Investors Advantage Plan prospectus and enrollment materials may be obtained by calling the Company at (800) 457-2983, at the corporate Web site – www.pinnaclewest.com, or by writing to:

Pinnacle West Capital Corporation
Shareholder Department
P.O. Box 52133
Phoenix, AZ 85072-2133

CORPORATE WEB SITE
www.pinnaclewest.com

TRANSFER AGENTS AND REGISTRAR
Common Stock
Pinnacle West Capital Corporation
Stock Transfer Department
P.O. Box 52134
Phoenix, Arizona 85072-2134
Or:
400 North 5th Street
Phoenix, Arizona 85004
Telephone: (602) 250-5505

SHAREHOLDER ACCOUNT AND ADMINISTRATIVE INFORMATION
Shareholder Department telephone number (toll-free): (800) 457-2983

STATISTICAL REPORT
A detailed Statistical Report for Financial Analysis for 1998-2003 will be available in April on the Company's Web site or by writing to the Investor Relations Department.

INVESTOR RELATIONS CONTACTS
Rebecca L. Hickman, Director, Investor Relations
Lisa Malagon, Manager
P.O. Box 53999 Station 9998
Phoenix, Arizona 85072-3999
Telephone: (602) 250-5668
Fax: (602) 250-2789

STATEWIDE ASSOCIATION FOR UTILITY INVESTORS
The Arizona Utility Investors Association represents the interests of investors in Arizona utilities. If interested, send your name and address to:

Arizona Utility Investors Association
P.O. Box 34805
Phoenix, Arizona 85067
(602) 257-9200
www.auia.org

ENVIRONMENTAL, HEALTH AND SAFETY REPORT
To view the APS Environmental, Health and Safety Report please visit www.aps.com, or to receive a printed summary report, call (602) 250-3259.

printed on recycled paper.

IMPORTANT NOTICE TO SHAREHOLDERS:
Pinnacle West posts quarterly results and other important information on its Web site (www.pinnaclewest.com). If you would like to receive news by regular mail, fax or e-mail, let us know by mail or phone at the addresses and numbers listed on this page. Also, let us know if you would like to be kept abreast of legislative and regulatory activities at the state and federal levels that could impact investor-owned utilities.

Campbell Fisher Design www.cfd2k.com

PINNACLE WEST
CAPITAL CORPORATION

SOUTHERN CALIFORNIA
EDISON®
An *EDISON INTERNATIONAL*® Company

2003 Annual Report

SCE003

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

SCE, a 118-year-old electric utility, serves a 50,000-square-mile area of central, coastal and southern California.

Contents

INTRODUCTION

This Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) contains forward-looking statements. These statements are based on Southern California Edison's (SCE) knowledge of present facts, current expectations about future events and assumptions about future developments. Forward-looking statements are not guarantees of performance; they are subject to risks and uncertainties that could cause actual future outcomes and results of operations to be materially different from those set forth in this discussion. Important factors that could cause actual results to differ are discussed throughout this MD&A, including in the management overview and the discussions of liquidity and market risk exposures.

The MD&A is presented in 11 major sections. The MD&A begins with (1) a management overview, which includes a summary of the major objectives for 2003 and 2004, a brief review of the company's consolidated earnings for 2003, and a description of how SCE earns revenue and income. The remaining sections of the MD&A include: (2) Liquidity; (3) Market Risk Exposures; (4) Regulatory Matters; (5) Other Developments; (6) Results of Operations and Historical Cash Flow Analysis; (7) Disposition and Discontinued Operations; (8) Acquisition; (9) Critical Accounting Policies; (10) New Accounting Principles; and (11) Commitments.

MANAGEMENT OVERVIEW

Summary

SCE was significantly impacted by California's energy crisis from 2000 into 2002. In 2003, SCE's management focused on restoring the company's financial health, chiefly by accomplishing three crucial objectives:

- Validating and completing SCE's recovery of power procurement costs arising from the energy crisis. In July 2003, SCE completed recovery of $3.6 billion of procurement-related obligations through the regulatory account known as the Procurement-Related Obligations Account (PROACT). By late 2003, both the California Supreme Court and the United States Court of Appeals for the Ninth Circuit (Ninth Circuit) had issued decisions upholding the 2001 settlement agreement with the California Public Utilities Commission (CPUC) that provided for creation of the PROACT and SCE's recovery of procurement-related costs. (See "Regulatory Matters—Generation and Power Procurement—CPUC Litigation Settlement Agreement," and "—PROACT Regulatory Asset.")

- Rebalancing SCE's capital structure to levels authorized by the CPUC. (See "Liquidity.") This was largely accomplished by a dividend to Edison International in December 2004 and financing activities in early 2004.

- Achieving an investment grade credit rating. In the fourth quarter of 2003, Moody's Investors Service and Standard & Poor's both raised SCE's credit ratings to investment grade. (See "Liquidity.")

In addition to SCE's ongoing emphasis on operational excellence, including system reliability, safety, customer satisfaction and employee development, during 2004 SCE's management will seek to further strengthen the company's financial and regulatory position by focusing on the following key objectives:

- Achieving sound regulatory outcomes, including a fair and durable regulatory framework, rate stability, and full recovery of energy procurement costs.

- Developing new resources, such as the proposed Mountainview plant, and investing in other major capital projects when customer and shareholder value are enhanced.

These objectives are discussed below in "—Issues Overview" and succeeding sections of this MD&A.

SCE recorded earnings of $922 million in 2003, compared to $1.2 billion in 2002, which included a gain of $480 million related to a regulatory decision on utility-retained generation (URG). Excluding this one-time gain 2002 gain, SCE's earnings increased $174 million over 2002. Major factors contributing to the increase over the prior year included the resolution of significant regulatory proceedings and a $44 million gain on the sale of SCE's fuel oil pipeline business. For a detailed review and analysis of the consolidated results of operations and historical cash flow analysis, see "Results of Operations and Historical Cash Flow Analysis" section.

Background

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 Federal Energy Regulatory Commission (FERC). SCE bills its customers for the sale of electricity at rates authorized by these two commissions. These rates are categorized into two groups: base rates and cost-recovery 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 the net book value of SCE's investment in generation and distribution plant (or rate base). Base rates provide for recovery of operations and maintenance (O&M) 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 currently authorized by the CPUC through a General Rate Case (GRC) proceeding. In a GRC proceeding, SCE files an application with the CPUC to update its authorized annual revenue requirement. After a review process and hearings, the CPUC sets an annual revenue requirement by multiplying an authorized rate of return, determined in annual cost of capital proceedings (as discussed below), by rate base, then adding to this amount the adopted O&M costs and capital-related carrying costs. Adjustments to the revenue requirement for the remaining years of a typical three-year GRC cycle are requested from the CPUC based on criteria established in a GRC proceeding for escalation in O&M costs, changes in capital-related costs and the expected number of nuclear refueling outages. Variations in generation and distribution revenue arising from the difference between forecast and actual electricity sales are recorded in balancing accounts for future recovery or refund, and do not impact SCE's operating profit, while differences between forecast and actual costs, other than cost-recovery costs (see below), do impact profitability.

SCE's capital structure, including the authorized rate of return, is regulated by the CPUC and is determined in annual cost of capital proceedings. The rate of return is a blend of a return on equity and cost of long-term debt and preferred stock. SCE's 2003 cost of capital decision, issued on November 7, 2002, will remain in effect throughout 2004. Accordingly, SCE's CPUC-authorized rate of return of 9.75%, return on common equity of 11.6% and authorized rate-making capital structure will be maintained through 2004.

Current CPUC ratemaking also provides for performance incentives or penalties for differences between actual results and GRC-determined standards of reliability, customer satisfaction and employee safety.

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 when the application is filed, and revenue is subject to refund until a FERC decision is issued. SCE currently receives approximately $260 million in annual revenue to recover the costs associated with its transmission function and to earn a reasonable return on its $1.1 billion transmission rate base.

Cost-Recovery Rates: Revenue requirements to recover SCE's costs of fuel, power procurement, demand-side management programs, nuclear decommissioning costs, and rate reduction debt requirements are authorized in various CPUC proceedings on a cost-recovery basis, with no markup for return or profit. Approximately 50% 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 in these categories in future proceedings, under- or over-collections in these balancing accounts can build rapidly due to fluctuating prices (particularly in power procurement) and can greatly impact cash flows. 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.

As described below under "Regulatory Matters—Generation and Power Procurement—CDWR Power Purchases and Revenue Requirement Proceedings," the California Department of Water Resources (CDWR) began purchasing power on behalf of utility customers during the California energy crisis. In addition to billing its customers for SCE's power procurement activities, SCE also bills and collects from its customers for power purchased and sold by the CDWR, CDWR bond-related charges and direct access exit fees. These amounts are remitted to the CDWR as they are collected and are not recognized as revenue by SCE. As a result, these transactions should have no impact on SCE's earnings or cash flow.

For a discussion of important issues related to the rate-making process, see the "Regulatory Matters" section.

Issues Overview

This overview discusses key business issues facing SCE. It is not intended to be an exhaustive discussion. It includes issues that could materially affect SCE's earnings, cash flow or business risk. The overview includes a discussion of current and planned capital expenditures (including the acquisition and construction of the Mountainview project, either potential expenditures or the possibility of a shutdown at the Mohave Generating Station (Mohave), and costs of replacing the steam generators at the San Onofre Nuclear Generating Station (San Onofre)), anticipated procurement requirements (including the effects of a resource adequacy requirement, community aggregation, and related ratemaking), and the 2003 and 2006 CPUC General Rate Cases.

The issues discussed in this overview are described in more detail in the remainder of this MD&A.

SCE's utility business is experiencing significant growth in actual and planned capital expenditures. SCE plans to spend up to $1.9 billion during 2004, compared to $1.2 billion in 2003. The growth in spending will require a partial reinvestment of earnings and issuance of debt securities to maintain a balanced capital structure, as required by the CPUC. For 2005 and beyond, capital spending is anticipated to remain at levels substantially above historical levels, but somewhat below planned spending for 2004.

Each of SCE's business areas (distribution, transmission and generation) is contributing to the capital spending growth. The distribution area, which represents approximately 70% of SCE's rate base, is experiencing continued expansion of the number of customer accounts. Beginning with a base of

4.6 million active accounts, for 2004, SCE expects to add approximately 60,000 new accounts, and forecasts a similar level of activity over the next several years. SCE also forecasts that it will need to accelerate the replacement of distribution poles, transformers and other infrastructure to maintain existing levels of system reliability.

SCE forecasts that expenditures for transmission facilities will substantially increase over the balance of the decade. SCE is now planning for and beginning to construct new substations to meet customer load-growth requirements. Moreover, SCE is conducting preliminary engineering on new and existing transmission lines that would expand the capacity to bring in additional energy from the Southwest.

In 2004, generation capital expenditures will increase dramatically, driven primarily by the recently approved Mountainview project. In addition, SCE will spend in excess of $50 million at the San Onofre plant to construct facilities to protect the site against a design basis threat as determined by the Nuclear Regulatory Commission. These expenditures are in addition to ongoing capital expenditures to maintain the safety and reliability of SCE's nuclear, coal and hydroelectric facilities. Beyond 2004, SCE may replace the San Onofre steam generators in the 2009–2010 time frame. Given the lead-time requirements to fabricate the steam generators, SCE must make commitments to begin fabrication during 2004.

Recently, the CPUC ordered all load-serving entities to procure sufficient resources to meet their customers' needs. This resource adequacy requirement phases in over the 2005–2008 period and requires planning reserve margins of 15–17% of peak load. This resource adequacy requirement, combined with the anticipated closure of Mohave at the end of 2005, expected reductions in deliveries under CDWR contracts, expected expiration of contracts with some independent power producers known as qualifying facilities (QFs), and expected peak-load growth of 1.5–2.0% per year, will require SCE to either construct new generation facilities or enter into additional power-purchase contracts to provide for forecasted customer requirements. Implementation of the CPUC order will be addressed in workshops commencing in mid-March 2004.

At the same time that SCE is evaluating new generation investments and contractual obligations, SCE has raised fundamental concerns about the stability of its customer base in the CPUC's ongoing long-term procurement proceeding. The CPUC's direct access rules, the possible expansion of community choice aggregation, other forms of municipalization, and application of exit fees to departing customers all affect the ability of SCE to retain bundled service customers (customers who purchase power from SCE). It is SCE's goal to ensure that customers who depart from utility generation service pay their fair share of costs, and that costs are not unfairly shifted to remaining bundled service customers, which could have the effect of increasing SCE's rates and causing more customers to seek alternative providers.

SCE is aware that the concern for high rates was a contributing factor that led California regulators to deregulate the electric services industry in the mid-1990's. Today, SCE's system average rate is 12.3¢-per-kilowatt-hour (kWh) for bundled service customers and its average monthly bill is $79. On a cents-per-kWh basis, SCE's average rate is above the national average, but similar to the other investor-owned electric utilities in California. Therefore, SCE is focused on providing bundled service customers competitive and stable electric rates. But this focus must be balanced with the obligation to safely and reliably serve customers.

At the beginning of 2003, SCE resumed procurement of power for its bundled service customers. During 2003, much of management's attention was focused on establishing fair and reasonable rules for the procurement of power for utility customers. Additional work is needed. For 2004 and 2005, SCE forecasts that it will have a residual long position in the majority of hours. SCE's residual-net long position arises primarily because of the CPUC's allocation of CDWR contract energy. For the reasons listed above, such as customer growth and run-off of existing contracts, SCE expects to have

substantially greater power procurement requirements beyond 2005. The acquisition and construction of the Mountainview project, the replacement of the San Onofre steam generators and the expansion of transmission facilities are all part of SCE's plan to meet a portion of expected customer requirements. However, even more additional resources will be needed to meet those expected requirements.

To promote and ensure recovery of both generation investments and contract costs, SCE has established a corporate priority to secure a fair and durable regulatory framework. To this end, SCE supports adoption of Assembly Bill 2006, introduced by California's Speaker of the Assembly Fabian Nunez. The bill is pending before the California State Assembly.

SCE is in the final stages of its 2003 GRC proceeding, which will set annual base rates for the years 2003–2005 years. On February 13, 2004, SCE received a proposed decision from the administrative law judge that heard the 2003 GRC. SCE is seeking a $251 million increase in its annual base rate revenue, but the proposed decision would allow only a $15 million increase. SCE is disappointed with the proposed decision and will press for reinstatement of its requested amount by the CPUC commissioners. The CPUC commissioners can accept, reject, or modify any proposed decision.

SCE is now preparing its 2006 General Rate Case. SCE's preliminary application files in August 2004, with the application scheduled to file before year-end 2004. With the expected growth in capital spending discussed above, SCE expects that it will need further increases in its revenue requirement.

LIQUIDITY

SCE's liquidity is primarily affected by under- or over-collections of procurement-related costs as discussed in "Management Overview—Background" and access to capital markets or external financings. In the fourth quarter of 2003, Moody's Investors Service and Standard & Poor's both raised SCE's credit ratings to investment grade.

At December 31, 2003, SCE had cash and equivalents of $95 million. SCE's long-term debt, including current maturities, at December 31, 2003, was $4.5 billion. SCE has a $700 million credit facility that expires in December 2006. SCE drew $200 million on the facility on December 19, 2003. In addition, the facility supported letters of credit in the amount of $33 million at year-end 2003. At December 31, 2003, SCE had borrowing capacity under its credit facility of $467 million. SCE's 2004 cash requirements consist of:

- $125 million of 5.875% bonds due in September 2004;
- Approximately $246 million of rate reduction notes that are due at various times in 2004, but which have a separate cost recovery mechanism approved by state legislation and CPUC decisions;
- Projected capital expenditures of $1.9 billion, including the investment in the Mountainview project and related capital expenditures (see "Acquisition");
- Dividend payments to SCE's parent company;
- Fuel and procurement-related costs; and
- General operating expenses.

SCE expects to meet its continuing obligations and cash outflows for undercollections (if incurred) through cash and equivalents on hand, operating cash flows and short-term borrowings, when necessary.

Projected capital expenditures are expected to be financed through cash flows and the issuance of long-term debt.

SCE's capital structure is regulated by the CPUC. SCE's CPUC-authorized common equity to total capitalization ratio level is 48%. On October 16, 2003, SCE transferred, through a dividend to Edison International, $945 million of equity that exceeded the CPUC-authorized level. This dividend was a first step to rebalance SCE's capital structure in accordance with CPUC requirements. As of December 31, 2003, SCE's common equity to total capitalization ratio, for rate-making purposes, was approximately 55%.

In January 2004, SCE issued $975 million of first and refunding mortgage bonds. The issuance included $300 million of 5% bonds due in 2014, $525 million of 6% bonds due in 2034 and $150 million of floating rate bonds due in 2006. The proceeds were used to redeem $300 million of 7.25% first and refunding mortgage bonds due March 2026, $225 million of 7.125% first and refunding mortgage bonds due July 2025, $200 million of 6.9% first and refunding mortgage bonds due October 2018, and $100 million of junior subordinated deferrable interest debentures due June 2044. In March 2004, SCE remarketed approximately $550 million of pollution-control bonds with varying maturity dates ranging from 2008 to 2040.

SCE resumed procurement of its residual-net short (the amount of energy needed to serve SCE's customers from sources other than its own generating plants, power-purchase contracts and CDWR contracts) on January 1, 2003, and as of December 31, 2003, had posted approximately $66 million ($33 million in cash and $33 million in letters of credit) as collateral to secure its obligations under power-purchase contracts and to transact through the Independent System Operator (ISO) for imbalance energy. SCE's collateral requirements can vary depending upon the level of unsecured credit extended by counterparties, the ISO's credit requirements, changes in market prices relative to contractual commitments, and other factors.

SCE's liquidity may be affected by, among other things, matters described in "Regulatory Matters—Generation and Power Procurement—CPUC Litigation Settlement Agreement," "—CDWR Power Purchases and Revenue Requirement Proceedings," and "—Generation Procurement Proceedings" sections.

MARKET RISK EXPOSURES

SCE's primary market risks include fluctuations in interest rates, generating fuel commodity prices and volume and counterparty credit. Fluctuations in interest rates can affect earnings and cash flows. However, fluctuations in fuel prices and volumes and counterparty credit losses temporarily affect cash flows, but should not affect earnings.

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 and to fund business operations, as well as to finance capital expenditures. The nature and amount of SCE's long-term and short-term debt can be expected to vary as a result of future business requirements, market conditions and other factors. In addition, SCE's authorized return on common equity (11.6% for 2003 and 2004), 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, 2003, SCE did not believe that its short-term debt and current portion of long-term debt and preferred stock was subject to interest rate risk, due to the fair market value being approximately equal to the carrying value.

At December 31, 2003, the fair market value of SCE's long-term debt was $4.4 billion. A 10% increase in market interest rates would have resulted in a $166 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 $183 million increase in the fair market value of SCE's long-term debt. At December 31, 2003, the fair market value of SCE's preferred stock subject to mandatory redemption was $139 million. A 10% increase in market interest rates would have resulted in a $12 million decrease in the fair market value of SCE's preferred stock subject to mandatory redemption. A 10% decrease in market interest rates would have resulted in a $14 million increase in the fair market value of SCE's preferred stock subject to mandatory redemption.

Generating Fuel Commodity Price Risk

SCE's purchased-power expense in 2003 was approximately 38% of SCE's total operating expenses. SCE recovers its reasonable power procurement costs through regulatory mechanisms established by the CPUC. The California public utilities code provides that the CPUC shall adjust rates, or order refunds, to amortize undercollections or overcollections of power procurement costs. Until January 1, 2006, the CPUC must adjust rates if the undercollection or overcollection exceeds 5% of SCE's prior year's procurement costs, excluding revenue collected for the CDWR. As a result of these regulatory mechanisms, changes in energy prices may impact SCE's cash flows but should have no impact on earnings.

On January 1, 2003, SCE resumed procurement of its residual-net short. SCE forecasts that it will have a residual long position in the majority of hours for 2004. SCE's residual-net long position arises from an expected increase in deliveries under CDWR contracts allocated to SCE's customers. SCE has incorporated a price and volume forecast from expected sales of residual-net long power in its 2004 procurement plan filed with the CPUC, as well as in the revenue forecast used for setting rates. If actual prices or volumes vary from forecast, SCE's cash flow would be temporarily impacted, but should not affect earnings. For 2004 and beyond, several factors could cause SCE's residual-net short to be much larger than expected, including the return of direct access customers (customers who choose to purchase power directly from an electric service provider other than SCE) to utility service, lower utility generation due to expected or unexpected outages or plant closures, lower deliveries under third-party power contracts, higher than anticipated demand for electricity, or displacement of existing generation resources with economic short-term transactions. Such an increase in procurement requirements could lead to temporary revenue undercollections if the costs to purchase the additional energy were to exceed the amount recovered in rates.

SCE anticipates it will need to purchase additional capacity and/or ancillary services to meet its peak-energy requirements in 2004 and 2005. In 2006, SCE's residual-net short exposure will increase significantly from the reduction in expected CDWR power deliveries, expiration of certain contracts with QFs, expected shutdown of Mohave, and load growth.

Pursuant to CPUC decisions, SCE, as the CDWR's limited agent, arranges for natural gas and performs related services for CDWR contracts allocated to SCE by the CPUC. Financial and legal responsibility for the allocated contracts remains with the CDWR. The CDWR, through the coordination of SCE, has hedged a portion of its expected natural gas requirements for certain contracts allocated to SCE. To the extent the price of natural gas were to increase above the levels assumed for cost recovery purposes, 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 purchases power from QFs under CPUC state-mandated contracts. Contract energy prices for most nonrenewable QFs are tied to the Southern California border price of natural gas established on a monthly basis. The CPUC has authorized SCE to hedge a majority of its natural gas price exposure associated with these QF contracts. During 2003, SCE substantially hedged the risk of increasing natural gas prices through hedging instruments purchased in late 2001 pursuant to authority granted by the CPUC. The cost of these hedging instruments was recovered through PROACT. None of these hedging instruments were outstanding as of December 31, 2003. The CPUC approved SCE's short-term resource plan, which includes hedging of natural gas price exposure for its existing QF contracts for 2004. These hedging costs are recovered through a balancing account known as Energy Resource Recovery Account (ERRA) and should have no impact on earnings. SCE cannot predict with certainty whether in the future it will be able to hedge customer risk for other commodities on favorable terms or that the cost of such hedges will be fully recovered in rates.

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. 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 should not affect earnings.

REGULATORY MATTERS

This section of the MD&A describes SCE's regulatory matters in three main subsections:

- generation and power procurement;
- transmission and distribution; and
- other regulatory matters.

Generation and Power Procurement

CPUC Litigation Settlement Agreement

During the California energy crisis, prices charged by sellers of wholesale power escalated far beyond what SCE was permitted by the CPUC to charge its customers. In November 2000, SCE filed a lawsuit against the CPUC in federal district court seeking a ruling that SCE is entitled to full recovery of its electricity procurement costs incurred during the energy crisis in accordance with the tariffs filed with the FERC. In October 2001, SCE and the CPUC entered into a settlement of SCE's lawsuit against the CPUC. A key element of the 2001 CPUC settlement agreement was the establishment of a $3.6 billion regulatory balancing account, called the PROACT, as of August 31, 2001. The Utility Reform Network (TURN) and other parties appealed to the Ninth Circuit seeking to overturn the stipulated judgment of the federal district court that approved the 2001 CPUC settlement agreement. On September 23, 2002, the Ninth Circuit issued its opinion affirming the federal district court on all claims, with the exception of the challenges founded upon California state law, which the Ninth Circuit referred to the California Supreme Court.

On August 21, 2003, the California Supreme Court issued its decision on the certified questions on challenges founded upon California state law, concluding that the 2001 CPUC settlement agreement did not violate California law in any of the respects raised by the Ninth Circuit. Specifically, the California Supreme Court concluded that: (1) the commissioners of the CPUC had the authority to propose the stipulated judgment under the provisions of California's restructuring statute, Assembly Bill 1890, as amended or impacted by subsequent legislation; (2) the procedures employed by the CPUC in entering the stipulated judgment did not violate California's open meeting law for public agencies; and (3) the stipulated judgment did not violate California's public utilities code by allegedly altering rates without a public hearing and issuance of findings.

On October 22, 2003, the California Supreme Court denied TURN's petition for rehearing of the decision. The matter was returned to the Ninth Circuit for final disposition, subject to any efforts by TURN to pursue further federal appeals. On December 19, 2003, the Ninth Circuit unanimously affirmed the original stipulated judgment of the federal district court, and no petition for rehearing was filed. On January 12, 2004, the Ninth Circuit issued its mandate, relinquishing jurisdiction of the case and returning jurisdiction to the federal district court. TURN and those parties whose appeals to the Ninth Circuit were consolidated with TURN's appeal currently have 90 days from December 19, 2003 in which to seek discretionary review from the United States Supreme Court. SCE continues to believe it is probable that recovery of its past procurement costs through regulatory mechanisms, including the PROACT, will not be invalidated. However, SCE cannot predict with certainty the ultimate outcome of further legal proceedings, if any.

PROACT Regulatory Asset

In accordance with the 2001 CPUC settlement agreement described above and an implementing resolution adopted by the CPUC, in the fourth quarter of 2001, SCE established the PROACT regulatory balancing account, with an initial balance of approximately $3.6 billion. The initial balance reflected the net amount of past procurement-related liabilities to be recovered by SCE. On a monthly basis, the difference between SCE's revenue from retail electric rates (including surcharges) and the costs that SCE was authorized by the CPUC to recover in retail electric rates was applied to the PROACT until SCE fully recovered the balance.

At July 31, 2003, the PROACT regulatory balancing account was overcollected by $148 million. On October 14, 2003, the CPUC approved SCE's advice filing which allowed SCE to transfer this July 31, 2003 overcollected PROACT balance and a temporary surcharge balancing account overcollection (see "—Generation and Power Procurement—Temporary Surcharges") to the ERRA (discussed below) on August 1, 2003, and to implement a $1.2 billion customer rate reduction effective August 1, 2003.

Energy Resource Recovery Account Proceedings

In an October 24, 2002 decision, the CPUC established the ERRA as the rate-making mechanism to track and recover SCE's: (1) fuel costs related to its generating stations; (2) purchased-power costs related to cogeneration and renewable contracts; (3) purchased-power costs related to existing interutility and bilateral contracts that were entered into before January 17, 2001; and (4) new procurement-related costs incurred on or after January 1, 2003 (the date on which the CPUC transferred back to SCE the responsibility for procuring energy resources for its customers). As described in "Management Overview," SCE recovers these costs on a cost-recovery basis, with no markup for return or profit. SCE files annual forecasts of the above-described costs that it expects to incur during the following year. As these costs are subsequently incurred, they will be tracked and recovered through the ERRA, but are subject to a reasonableness review in a separate annual ERRA application. If the ERRA overcollection

or undercollection exceeds 5% of SCE's prior year's procurement costs, SCE can request an emergency rate adjustment in addition to the annual forecast and reasonableness ERRA applications.

SCE submitted its first ERRA forecast application in April 2003, in which it forecast procurement-related costs for the 2003 calendar year of $2.5 billion. On January 22, 2004, the CPUC issued a decision that approved SCE's forecast as submitted. The CPUC issued a proposed decision on February 24, 2004, approving SCE's 2004 forecast revenue requirement and rates for both generation and delivery services.

In October 2003, SCE submitted its first ERRA reasonableness review application, in which it requested the CPUC find its procurement-related operations during the period from September 1, 2001 through June 30, 2003 to be reasonable. Because this is the first annual review of this activity, pursuant to new California state law, the CPUC's interpretation and application of California state law is uncertain. SCE cannot predict with certainty the outcome of its application and recovery of its procurement-related operations costs.

Pursuant to the assigned commissioner's scoping memo issued on December 9, 2003, the CPUC's Office of Ratepayer Advocates (ORA) was allowed to review the accounting calculations used in the PROACT mechanism. The ORA testimony, due on March 19, 2004, will include an audit of these accounting calculations. Hearings are scheduled to be held during April 2004.

Utility-Retained Generation

As a result of an April 2002 CPUC decision, SCE's retained generation assets were returned to cost-of-service ratemaking after operating in a deregulated environment since 1998. The CPUC decision provided for the: (1) recovery of costs for all URG components other than San Onofre Units 2 and 3, subject to reasonableness review by the CPUC; (2) retention of the incremental cost incentive pricing mechanism (ICIP) for San Onofre Units 2 and 3 through 2003; (3) establishment of an amortization schedule for SCE's nuclear facilities that reflects their current remaining Nuclear Regulatory Commission license durations, using unamortized balances as of January 1, 2001 as a starting point; (4) establishment of balancing accounts for the costs of utility generation, purchased power, and ancillary services purchased from the ISO; and (5) continuation of the use of SCE's last CPUC-authorized return on common equity of 11.6% for SCE's URG rate base other than San Onofre Units 2 and 3, and the 7.35% return on rate base for San Onofre Units 2 and 3 under the ICIP. SCE will operate under the April 2002 CPUC decision until implementation of the 2003 GRC (see "—Transmission and Distribution—2003 General Rate Case Proceeding").

CDWR Power Purchases and Revenue Requirement Proceedings

In accordance with an emergency order by the Governor of California, the CDWR began making emergency power purchases for SCE's customers on January 17, 2001. In February 2001, a California law was enacted which authorized the CDWR to: (1) enter into contracts to purchase electric power and sell power at cost directly to SCE's retail customers; and (2) issue bonds to finance those electricity purchases. During the fourth quarter of 2002, the CDWR issued $11 billion in bonds to finance its electricity purchases. The CDWR's total statewide power charge and bond charge revenue requirements are allocated by the CPUC among the customers of SCE, Pacific Gas and Electric (PG&E) and San Diego Gas & Electric (SDG&E). Amounts billed to and collected from SCE's customers for electric power purchased and sold by the CDWR (approximately $1.7 billion in 2003) are remitted directly to the CDWR and are not recognized as revenue by SCE.

Direct Access Proceedings

From 1998 through mid-September 2001, SCE's customers were able to choose to purchase power directly from an electric service provider other than SCE (thus becoming direct access customers) or continue to purchase power from SCE. During that time, direct access customers received a credit for the generation costs SCE saved by not serving them, resulting in additional undercollected power procurement costs to SCE during 2000 and 2001. On March 21, 2002, the CPUC issued a decision affirming that new direct access arrangements entered into by SCE's customers after September 20, 2001 are invalid. That decision did not affect direct access arrangements in place before that date.

In May 2003, a CPUC decision allowed customers with valid direct access arrangements to switch back and forth between bundled service provided by SCE and direct access. This decision, as well as CPUC decisions or proceedings discussed below, affects SCE's ability to predict the size of its customer base, the amount of bundled service load for which it must procure or generate electricity, its net-short position and its ability to plan for resource requirements.

The CPUC has received several petitions requesting clarification of previous decisions on whether to allow load growth on existing direct access accounts or add new accounts if necessary to accommodate direct access customers who relocate their facilities. Recently, the CPUC agreed, in response to one of these petitions, to allow direct access customers to add new accounts when relocating facilities as long as there is no increase in a customer's total eligible direct access load. SCE cannot predict how the CPUC will rule on the remaining petitions. If the CPUC allows load growth on existing direct access accounts and allows new direct access accounts to be added notwithstanding the suspension of direct access, the level of direct access load in SCE's territory could rise considerably, resulting in a shift of a greater portion of SCE's costs to bundled service customers.

The CPUC has also opened a proceeding to identify issues relating to the implementation of a 2002 California law authorizing community choice aggregation. This form of direct access allows local governments to combine the loads of its residents, businesses, and municipal facilities in a community-wide electricity buyers program and to create an entity called a community choice aggregator. Hearings on this matter are scheduled to begin in May 2004. Depending on how many, if any, cities choose to participate in community choice aggregation, a large amount of load could depart from SCE's bundled service, resulting in additional shifting of cost responsibility.

The CPUC has issued decisions or has opened proceedings to establish various charges (exit fees) for customers who (1) switch to another electric service provider, (2) switch to a municipal utility; or (3) install onsite generation facilities or arrange to purchase power from another entity that installs such facilities. The charges recovered from these customers are used to reduce SCE's rates to bundled service customers and have no impact on earnings.

Temporary Surcharges

A March 2001 CPUC decision, authorized a 3¢-per-kWh revenue surcharge to SCE's customers and made permanent a 1¢-per-kWh surcharge to SCE's customers authorized in January 2001. In addition, the CPUC authorized an additional 0.6¢-per-kWh catch-up surcharge for a twelve-month period, beginning in June 2001, to compensate SCE for a delay in collecting the 3¢-per-kWh surcharge. These surcharges were used for SCE's procurement costs.

The CPUC later allowed the continuation of the 0.6¢-per-kWh catch-up surcharge. Amounts collected between June 2002 and December 2002 were to be used to recover 2003 procurement costs. As a result, at December 31, 2002, this revenue ($187 million of surcharge revenue) was credited to a regulatory

liability account until it was used to offset SCE's higher 2003 procurement revenue requirement. Between January 1, 2003 and July 31, 2003, $150 million of this regulatory liability account was amortized into revenue. The remaining balance of $37 million was transferred to the ERRA as of August 1, 2003.

The $1.2 billion customer rate reduction plan implemented by SCE eliminated all of the temporary surcharges (see "—Generation and Power Procurement—PROACT Regulatory Asset").

Generation Procurement Proceedings

SCE resumed power procurement responsibilities for its residual-net short position on January 1, 2003, pursuant to CPUC orders and California statutes passed in 2002. The current regulatory and statutory framework requires SCE to assume limited responsibilities for CDWR contracts allocated by the CPUC, and provide full power procurement responsibilities on the basis of annual short-term procurement plans, long-term resource plans and increased procurement of renewable resources.

Short-Term Procurement Plan

In 2003, SCE operated under a CPUC-approved short-term procurement plan, which includes contracts entered into during a transitional period beginning in August 2002 for deliveries in 2003 and the allocation of CDWR contracts. In December 2003, the CPUC adopted a 2004 procurement plan for SCE, which established a target level for spot market purchases equal to 5% of monthly need, and allowed SCE to enter into contracts of up to five years.

Long-Term Resource Plan

On April 15, 2003, SCE filed its long-term resource plan with the CPUC, which includes a 20-year forecast. SCE's long-term resource plan included both a preferred plan and an interim plan (both described below). On January 22, 2004, the CPUC issued a decision which did not adopt any long-term resource plan, but adopted a framework for resource planning. Until the CPUC approves a long-term resource plan for SCE, SCE will operate under its interim resource plan.

- Preferred Resource Plan: The preferred resource plan contains long-term commitments intended to encourage investment in new generation and transmission infrastructure, increase long-term reliability and decrease price volatility. These commitments include energy efficiency and demand-response investments, additional renewable resource contracts that will meet or exceed the requirements of legislation passed in 2002, additional utility and third-party owned generation, and new major transmission projects.

- Interim Resource Plan: The interim resource plan, by contrast, relies exclusively on new short- and medium-term contracts with no long-term resource commitments (except for new renewable contracts).

In its long-term resource plan filing, SCE maintained that implementation of its preferred resource plan requires resolution of various issues including: (1) stabilizing SCE's customer base; (2) restoring SCE's investment-grade creditworthiness; (3) restructuring regulations regarding energy efficiency and demand-response programs; (4) removing barriers to transmission development; (5) modifying prior decisions, which impede long-term procurement; and (6) adopting a commercially realistic cost-recovery framework that will enable utilities to obtain financing and enable contracting for new generation.

Under the framework adopted in the CPUC's January 22, 2004 decision, all load-serving entities in California have an obligation to procure sufficient resources to meet their customers' needs. This resource adequacy requirement phases in over the 2005–2008 period and requires planning reserve margins of 15–17% of peak load. The decision requires SCE to enter into forward contracts for 90% of SCE's summer peaking needs a year in advance and to file a revised long-term resource plan in 2004. The decision does not comprehensively address important issues SCE has raised about its customer base, recovery of indirect procurement costs (including debt equivalence) and other matters.

Procurement of Renewable Resources

As part of SCE's resumption of power procurement, in accordance with a California statute passed in 2002, SCE is required to increase its procurement of renewable resources by at least 1% of its annual electricity sales per year so that 20% of its annual electricity sales are procured from renewable resources by no later than December 31, 2017. In June 2003, the CPUC issued a decision adopting preliminary rules and guidance on renewable procurement-related issues, including penalties for noncompliance with renewable procurement targets. As of December 31, 2003, SCE procured approximately 18% of its annual electricity from renewable resources.

SCE has received bids for renewable resource contracts in response to a solicitation it made in August 2003, and is proceeding to enter into negotiations for contracts with some bidders based upon its preliminary bid evaluation.

CDWR Contract Allocation and Operating Order

The CDWR power-purchase contracts entered into as a result of the California energy crisis have been allocated on a contract-by-contract basis among SCE, PG&E and SDG&E, in accordance with a 2002 CPUC decision. SCE only assumes scheduling and dispatch responsibilities and acts only as a limited agent for the CDWR for contract implementation. Legal title, financial reporting and responsibility for the payment of contract-related bills remain with the CDWR. The allocation of CDWR contracts to SCE significantly reduces SCE's residual-net short and also increases the likelihood that SCE will have excess power during certain periods. SCE has incorporated CDWR contracts allocated to it in its procurement plans. Wholesale revenue from the sale of excess power, if any, is prorated between the CDWR and SCE.

SCE's maximum annual disallowance risk exposure for contract administration, including administration of allocated CDWR contracts and least cost dispatch of CDWR contract resources, is $37 million. In addition, gas procurement, including hedging transactions, associated with CDWR contracts is included within the cap.

Mohave Generating Station and Related Proceedings

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

Due to the lack of progress in negotiations with the Tribes and other parties to resolve several coal and water supply issues, SCE's application stated that SCE would probably be unable to extend Mohave's operation beyond 2005. The uncertainty over a 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 pollution-control equipment that must be put in place in order for Mohave to continue to operate beyond 2005, pursuant to a 1999 consent decree concerning air quality.

Negotiations are continuing among the relevant parties in an effort to resolve the coal and water supply issues, but no resolution has been reached. The Mohave co-owners, the Tribes, and the federal government have recently finalized a memorandum of understanding under which the Mohave co-owners will fund, subject to the terms and conditions of the memorandum of understanding, a $6 million study of a possible alternative groundwater source for the slurry water. The study is expected to begin in early 2004. SCE and other parties submitted further testimony and made various other filings in 2003 in SCE's application proceeding. On February 9, 2004, the CPUC held a prehearing conference to discuss whether additional testimony and hearings are needed to determine the future of the plant. The CPUC has not issued any ruling as result of the prehearing conference, but has indicated that further testimony can be expected in early to mid-2004. The outcome of the coal and water negotiations and SCE's application are not expected to impact Mohave's operation through 2005, but could have a major impact on SCE's long-term resource plan.

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

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

Transmission and Distribution

2003 General Rate Case Proceeding

On May 3, 2002, SCE filed its application for a 2003 GRC, requesting: (1) a 2003 revenue requirement of approximately $3.1 billion; (2) a 2004 revenue requirement of approximately $3.5 billion; and (3) a 2005 revenue requirement of approximately $3.7 billion. These revenue requirements were based on SCE's projected rate base amounts of $7.8 billion in 2003, $8.2 billion in 2004 and $8.5 billion in 2005. When compared to forecast revenue at currently authorized rates (approximately $2.8 billion), SCE's 2003 GRC request was an increase of $286 million, which was subsequently revised to an increase of $251 million. The requested revenue increase for 2003 was primarily related to capital additions, updated depreciation costs and projected increases in pension and benefit expenses. The application also proposed an estimated base rate revenue decrease of $78 million in 2004, and a subsequent increase of $116 million in 2005. The forecast reduction in 2004 was largely attributable to the expiration of the San Onofre ICIP rate-making mechanism at year-end 2003 and a forecast of increased sales. The expiration of San Onofre ICIP mechanism is expected to decrease SCE's 2004 earnings by approximately $100 million. Beginning in 2004, San Onofre Units 2 and 3 cost recovery reverts to cost-of-service ratemaking.

In a proposed decision issued on February 13, 2004, a CPUC administrative law judge recommended that the CPUC adopt only $15 million of the $251 million increase in authorized base rate revenue requirement that SCE had requested. SCE filed comments opposing parts of the proposed decision in an

attempt to restore important components of the requested revenue requirement. The CPUC is scheduled to vote on the proposed decision on March 16, 2004, either modifying or accepting it. If an alternate decision is proposed, a final decision could be delayed into April 2004. If the CPUC adopts the administrative law judge's proposed decision without modification, and if SCE does not reduce its expected capital or operating expenditures accordingly, SCE estimates that on an annual basis SCE's earnings per share would be about 15¢-per-share lower and cash flow would be approximately $135 million lower than if SCE's base rate request had been granted in full. SCE cannot predict with certainty the final outcome of SCE's GRC application.

Because processing of the GRC took longer than initially scheduled, in May 2003 the CPUC approved SCE's request to establish a memorandum account to track the revenue requirement increase during the period between May 22, 2003 (the date a final CPUC decision was originally scheduled to be issued) and the date a final decision is ultimately adopted. The revenue requirement approved in the final GRC decision will be effective retroactive to May 22, 2003. Any balance in the GRC memorandum account authorized by the CPUC would be recovered in rates beginning in 2004, together with the combined revenue requirement authorized by the CPUC in the GRC decision for 2003 and 2004.

Hearings to address revenue allocation and rate design issues have been continued until after the CPUC issues a decision on SCE's revenue requirement. Due to the implementation of SCE's $1.2 billion customer rate-reduction plan, rate design changes will not be effective until August 2004, at the earliest. Until SCE's 2003 GRC is implemented, SCE's revenue requirement related to distribution operations is determined through a performance-based rate-making (PBR) mechanism.

Electric Line Maintenance Practices Proceeding

In August 2001, the CPUC issued an order instituting investigation regarding SCE's overhead and underground electric line maintenance practices. The order was based on a report issued by the CPUC's Consumer Protection and Safety Division, which alleged a pattern of noncompliance with the CPUC's general orders for the maintenance of electric lines for 1998–2000. The order also alleged that noncompliant conditions were involved in 37 accidents resulting in death, serious injury or property damage. The Consumer Protection and Safety Division identified 4,817 alleged violations of the general orders during the three-year period; and the order put SCE on notice that it could be subject to a penalty of between $500 and $20,000 for each violation or accident. In its opening brief on October 21, 2002, the Consumer Protection and Safety Division recommended that SCE be assessed a penalty of $97 million.

On June 19, 2003, a CPUC administrative law judge issued a presiding officer's decision on the Consumer Protection and Safety Division report. The decision did the following:

- Fined SCE $576,000 for 2% of the alleged violations involving death, injury or property damage, failure to identify unsafe conditions or exceeding required inspection intervals. The decision did not find that any of the alleged violations compromised the integrity or safety of SCE's electric system or were excessive compared to other utilities.

- Ordered SCE to consult with the Consumer Protection and Safety Division and refine SCE's maintenance priority system consistent with the decision.

- Adopted an interpretation that all SCE's nonconformances with the CPUC's general orders for the maintenance of electric lines are violations subject to potential penalty.

On July 21, 2003, SCE filed an appeal with the CPUC challenging, among other things, the decision's interpretation of nonconformance. The Consumer Protection and Safety Division also appealed, challenging the fact that the decision did not penalize SCE for 4,721 of the 4,817 alleged violations. A final decision is scheduled to be issued on March 16, 2004.

Transmission Rate Case

In July 2000, the FERC issued a decision in SCE's 1998 transmission rate case in which it ordered a reduction of approximately $38 million to SCE's requested annual transmission revenue requirement of $213 million. In the decision, the FERC rejected SCE's proposed method for allocating overhead costs between transmission and distribution operations, which accounted for approximately $24 million of the $38 million reduction. After the FERC decision, SCE sought recovery in distribution rates from the CPUC. In third quarter 2003, the CPUC authorized recovery of $133 million of overhead costs for the period April 1, 1998 to August 31, 2002, and SCE credited this amount to provisions for regulatory adjustment clauses – net in the consolidated statements of income. On September 22, 2003, the ORA applied for rehearing of the matter. On February 11, 2004, the CPUC denied the ORA's request and reaffirmed its decision authorizing recovery.

Wholesale Electricity and Natural Gas Markets

In 2000, the FERC initiated an investigation into the justness and reasonableness of rates charged by sellers of electricity in the California Power Exchange (PX)/ ISO markets. On March 26, 2003, the FERC staff issued a report concluding that there had been pervasive gaming and market manipulation of both the electric and natural gas markets in California and on the West Coast during 2000–2001 and describing many of the techniques and effects of that market manipulation. 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. Under the 2001 CPUC settlement agreement, mentioned in "—Generation and Power Procurement—CPUC Litigation Settlement Agreement," 90% of any refunds actually realized by SCE will be refunded to customers, except for the El Paso Natural Gas Company settlement agreement discussed below.

El Paso Natural Gas Company entered into a settlement agreement with parties to a class action lawsuit (including SCE, PG&E and the State of California) settling claims stated in proceedings at the FERC and in San Diego County Superior Court that El Paso Natural Gas Company had manipulated interstate capacity and engaged in other anticompetitive behavior in the natural gas markets in order to unlawfully raise gas prices at the California border in 2000–2001. The San Diego County Superior Court approved the settlement on December 5, 2003. Notice of appeal of that judgment was filed by a party to the action on February 6, 2004. Accordingly, until the appeal is resolved, the judgment is not final and no refunds will be paid. Pursuant to a CPUC decision, SCE will refund to customers any amounts received under the terms of the El Paso Natural Gas Company settlement (net of legal and consulting costs) through its ERRA mechanism. In addition, amounts El Paso Natural Gas Company refunds to the CDWR will result in equivalent reductions in the CDWR's revenue requirement allocated to SCE.

On February 24, 2004, SCE and PG&E entered into a settlement agreement with The Williams Cos. and Williams Power Company, providing for approximately $140 million in refunds against some of Williams' power charges in 2000–2001. The allocation of refunds under the settlement agreement has not been determined. The settlement is subject to the approval of the FERC, the CPUC and the PG&E bankruptcy court.

Other Regulatory Matters

Catastrophic Event Memorandum Account

The catastrophic event memorandum account (CEMA) is a CPUC-authorized mechanism that allows SCE to immediately start the tracking of all of its incremental costs associated with declared disasters or emergencies and to subsequently receive rate recovery of its reasonably incurred costs upon CPUC approval. Incremental costs associated with restoring utility service; repairing, replacing or restoring damaged utility facilities; and complying with governmental agency orders are tracked in the CEMA. SCE currently has a CEMA for the bark beetle emergency and initiated a second CEMA associated with the fires that occurred in SCE territory in October 2003. Costs tracked through the CEMA mechanism are expected to be recovered in future rates with no impact on earnings. However, cash flow will be impacted due to the timing difference between expenditures and rate recovery.

Bark Beetle CEMA

On March 7, 2003, the Governor of California issued a proclamation declaring a state of emergency in Riverside, San Bernardino and San Diego counties where an infestation of bark beetles has created the potential for catastrophic forest fires. The proclamation requested that the CPUC direct utilities with transmission lines in these three counties to ensure that all dead, dying and diseased trees and vegetation are completely cleared from their utility rights-of-way to mitigate the potential fire damage. SCE estimates that it may incur several hundred million dollars in incremental expenses over the next several years to remove over 350,000 of these trees. This cost estimate is subject to significant change, depending on a number of evolving circumstances, including, but not limited to the spread of the bark beetle infestation, the speed at which trees can be removed, and tree disposal costs. In 2003, SCE removed approximately 26,000 dead or dying trees at an incremental expense of approximately $18 million which has been reflected in the CEMA as of December 31, 2003. SCE expects to submit an advice filing with the CPUC in the first quarter of 2004 to recover these costs. SCE estimates that it will spend up to $150 million on this project in 2004.

Fire-Related CEMA

During the last two weeks of October 2003, wildfires damaged SCE's electrical infrastructure, primarily in the San Bernardino Mountains of Southern California where an estimated 1,500 power poles and 220 transformers were damaged or downed. SCE notified the CPUC that it initiated a CEMA on October 21, 2003 to track the incremental costs to repair and restore its infrastructure. These costs are estimated to be approximately $30 million. The balance in this CEMA account is approximately $9 million as of December 31, 2003.

Holding Company Proceeding

In April 2001, the CPUC issued an order instituting investigation that reopened the past CPUC decisions authorizing utilities to form holding companies and initiated an investigation into, among other things: (1) whether the holding companies violated CPUC requirements to give first priority to the capital needs of their respective utility subsidiaries; (2) any additional suspected violations of laws or CPUC rules and decisions; and (3) whether additional rules, conditions, or other changes to the holding company decisions are necessary.

On January 9, 2002, the CPUC issued an interim decision interpreting the CPUC requirement that the holding companies give first priority to the capital needs of their respective utility subsidiaries. The decision stated that, at least under certain circumstances, holding companies are required to infuse all

types of capital into their respective utility subsidiaries when necessary to fulfill the utility's obligation to serve its customers. The decision did not determine whether any of the utility holding companies had violated this requirement, reserving such a determination for a later phase of the proceedings. On February 11, 2002, SCE and Edison International filed an application before the CPUC for rehearing of the decision. On July 17, 2002, the CPUC affirmed its earlier decision on the first priority requirement and also denied Edison International's request for a rehearing of the CPUC's determination that it had jurisdiction over Edison International in this proceeding. On August 21, 2002, Edison International and SCE jointly filed a petition in California state court requesting a review of the CPUC's decisions with regard to first priority requirements, and Edison International filed a petition for a review of the CPUC decision asserting jurisdiction over holding companies. PG&E and SDG&E and their respective holding companies filed similar challenges, and all cases have been transferred to the First District Court of Appeals in San Francisco. On November 26, 2003, the Court of Appeals issued an order indicating it would hear the cases but did not decide the merits of the petitions. Oral argument was held before the Court of Appeals on March 5, 2004, and the Court of Appeals is expected to rule within 90 days.

Investigation Regarding Performance Incentives Rewards

SCE is eligible under its CPUC-approved PBR mechanism to earn rewards or penalties based on its performance in comparison to CPUC-approved standards of reliability, customer satisfaction, and employee safety. SCE received two letters over the last year from 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 to SCE under the PBR provisions for customer satisfaction. SCE is conducting an internal investigation and has determined that some wrongdoing by a number of the service planning employees has occurred. SCE has informed the CPUC of its findings to date, and will continue to inform the CPUC of developments as the investigation progresses. SCE anticipates that, after the investigation is completed, there may be CPUC proceedings to determine whether any portion of past and potential rewards for customer satisfaction should be refunded or disallowed. It also is possible that penalties could be imposed. SCE recorded aggregate customer satisfaction rewards of $28 million for the years 1998, 1999, and 2000. Potential customer satisfaction rewards aggregating $10 million for 2001 and 2002 are pending before the CPUC and have not been recognized in income by SCE. SCE also had anticipated that it could be eligible for customer satisfaction rewards of about $10 million for 2003. SCE has not yet been able to determine whether or to what extent employee misconduct has compromised the surveys that are the basis for a portion of the awards. Accordingly, SCE cannot predict with certainty the outcome of this matter. SCE plans to complete its investigation as quickly as possible and cooperate fully with the CPUC in taking appropriate remedial action.

OTHER DEVELOPMENTS

Electric and Magnetic Fields

Electric and magnetic fields naturally result from the generation, transmission, distribution and use of electricity. Since the 1970s, concerns have been raised about the potential health effects of electric and magnetic fields. After 30 years of research, a health hazard has not been established to exist. Potentially important public health questions remain about whether there is a link between electric and magnetic fields exposures in homes or work and some diseases, and because of these questions, some health authorities have identified electric and magnetic fields exposures as a possible human carcinogen.

In October 2002, the California Department of Health Services released to the CPUC and the public its report evaluating the possible risks from electric and magnetic fields. The conclusions in the report of the California Department of Health Services contrast with other recent reports by authoritative health agencies in that the California Department of Health Services has assigned a substantially higher probability to the possibility that there is a causal connection between electric and magnetic fields exposures and a number of diseases and conditions, including childhood leukemia, adult leukemia, amyotrophic lateral sclerosis, and miscarriages.

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

Employee Compensation and Benefit Plans

On July 31, 2003, a federal district court held that the formula used in a cash balance pension plan created by International Business Machine Corporation (IBM) in 1999 violated the age discrimination provisions of the Employee Retirement Income Security Act of 1974. In its decision, the federal district court set forth a standard for cash balance pension plans. This decision, however, conflicts with the decisions from two other federal district courts and with the proposed regulations for cash balance pension plans issued by the Internal Revenue Service in December 2002. On February 12, 2004, the same federal district court ruled that IBM must make back payments to workers covered under this plan. IBM has indicated that it will appeal both decisions to the United States Court of Appeals for the Seventh Circuit. The formula for SCE's cash balance pension plan does not meet the standard set forth in the federal district court's July 31, 2003 decision. SCE cannot predict with certainty the effect of the two IBM decisions on SCE's cash balance pension plan.

Environmental Matters

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

Environmental Remediation

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

SCE's recorded estimated minimum liability to remediate its 26 identified sites is $92 million. In third quarter 2003, SCE sold certain oil storage and pipeline facilities. This sale caused a reduction in SCE's recorded estimated minimum environmental liability. The ultimate costs to clean up SCE's identified

sites may vary from its recorded liability due to numerous uncertainties inherent in the estimation process, such as: the extent and nature of contamination; the scarcity of reliable data for identified sites; the varying costs of alternative cleanup methods; developments resulting from investigatory studies; the possibility of identifying additional sites; and the time periods over which site remediation is expected to occur. SCE believes that, due to these uncertainties, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $238 million. The upper limit of this range of costs was estimated using assumptions least favorable to SCE among a range of reasonably possible outcomes.

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 $71 million for its estimated minimum environmental-cleanup costs expected to be recovered through customer rates.

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

SCE expects to clean up its identified sites over a period of up to 30 years. Remediation costs in each of the next several years are expected to range from $13 million to $25 million. Recorded costs for 2003 were $14 million.

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

Clean Air Act

The Clean Air Act requires power producers to have emissions allowances to emit sulfur dioxide. Power companies receive emissions allowances from the federal government and may bank or sell excess allowances. SCE expects to have excess allowances under Phase II of the Clean Air Act (2000 and later).

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

SCE's share of the costs of complying with the consent decree and taking other actions to continue operation of Mohave beyond 2005 is estimated to be approximately $605 million. SCE has received from the State of Nevada a permit to install the necessary pollution-control equipment. However, SCE has suspended its efforts to seek CPUC approval to install the Mohave pollution-control equipment because it has not obtained reasonable assurance of adequate coal and water supplies for operating Mohave beyond 2005. Unless adequate coal and water supplies are obtained, it will become necessary to shut down Mohave after December 31, 2005. If the station is shut down at that time, the shutdown is not

expected to have a material adverse impact on SCE's financial position or results of operations, assuming the remaining book value of the station (approximately $24 million as of December 31, 2003) and the related regulatory asset (approximately $66 million as of December 31, 2003), and plant closure and decommissioning-related costs are recoverable in future rates. SCE cannot predict with certainty what effect any future actions by the CPUC may have on this matter. See "Regulatory Matters—Generation and Power Procurement—Mohave Generating Station and Related Proceedings" for further discussion of the Mohave issues.

SCE's facilities are subject to the Clean Air Act's new source review (NSR) requirements related to modifications of air emissions sources at electric generating stations. Over the past five years, the United States Environmental Protection Agency (EPA) has initiated investigations of numerous electric utilities seeking to determine whether these utilities engaged in activities in violation of the NSR requirements, brought enforcement actions against some of those utilities, and reached settlements with some of those utilities. EPA has made information requests concerning SCE's Four Corners station. Other than this request for information, no enforcement-related proceedings have been initiated against any SCE facilities by EPA relating to NSR compliance.

Over this same period, EPA has proposed several regulatory changes to NSR requirements that would clarify and provide greater guidance to the utility industry as to what activities can be undertaken without triggering the NSR requirements. Several of these regulatory changes have been challenged in the courts. As a result of these developments, EPA's enforcement policy on alleged NSR violations is currently uncertain.

These developments will continue to be monitored by SCE to assess what implications, if any, they will have on the operation of domestic power plants owned or operated by SCE, or the impact on SCE's results of operations or financial position.

SCE's projected environmental capital expenditures are $2.3 billion, including the $605 million for Mohave discussed above for the 2004–2008 period, mainly for undergrounding certain transmission and distribution lines.

Federal Income Taxes

In August 2002, Edison International received a notice from the Internal Revenue Service asserting deficiencies in federal corporate income taxes for its 1994 to 1996 tax years. Included in these amounts are deficiencies asserted against SCE. Substantially all of SCE's tax deficiencies are timing differences and, therefore, amounts ultimately paid (exclusive of interest and penalties), if any, would benefit SCE as future tax deductions. SCE believes that it has meritorious legal defenses to those deficiencies and believes that the ultimate outcome of this matter will not result in a material impact on SCE's consolidated results of operations or financial position.

Navajo Nation Litigation

In June 1999, the Navajo Nation filed a complaint in the United States District Court for the District of Columbia (D.C. District Court) against Peabody Holding Company (Peabody) and certain of its affiliates, Salt River Project Agricultural Improvement and Power District, and SCE arising out of the coal supply agreement for Mohave. The complaint asserts claims for, among other things, violations of the federal Racketeer Influenced and Corrupt Organizations statute, interference with fiduciary duties and contractual relations, fraudulent misrepresentation by nondisclosure, and various contract-related claims. The complaint claims that the defendants' actions prevented the Navajo Nation from obtaining the full value in royalty rates for the coal. The complaint seeks damages of not less than $600 million, trebling of

that amount, and punitive damages of not less than $1 billion, as well as a declaration that Peabody's lease and contract rights to mine coal on Navajo Nation lands should be terminated. SCE joined Peabody's motion to strike the Navajo Nation's complaint. In addition, SCE and other defendants filed motions to dismiss.

Some of the issues included in this case were addressed by the United States Supreme Court in a separate legal proceeding filed by the Navajo Nation in the Court of Federal Claims against the United States Department of Interior. In that action, the Navajo Nation claimed that the Government breached its fiduciary duty concerning negotiations relating to the coal lease involved in the Navajo Nation's lawsuit against SCE and Peabody. On March 4, 2003, the Supreme Court concluded, by majority decision, that there was no breach of a fiduciary duty and that the Navajo Nation did not have a right to relief against the Government. Based on the Supreme Court's analysis, on April 28, 2003, SCE filed a motion to dismiss or, in the alternative, for summary judgment in the D.C. District Court action. The motion remains pending.

The Federal Circuit Court of Appeals, acting on a suggestion on remand filed by the Navajo Nation, held in a October 24, 2003 decision that the Supreme Court's March 24, 2003 decision was focused on three specific statutes or regulations and therefore did not address the question of whether a network of other statutes, treaties and regulations imposed judicially enforceable fiduciary duties on the United States during the time period in question. The Government and the Navajo Nation both filed petitions for rehearing of the October 24, 2003 Court of Appeals decision. Both petitions were denied on March 9, 2004.

SCE cannot predict with certainty the outcome of the 1999 Navajo Nation's complaint against SCE, the impact of the Supreme Court's decision in the Navajo Nation's suit against the Government on this complaint, or the impact of the complaint on the operation of Mohave beyond 2005.

San Onofre Steam Generators

Like other nuclear power plants with steam generators of the same design and material properties, San Onofre Units 2 and 3 have experienced degradation in their steam generators. Based on industry experience and analysis of recent inspection data, SCE has determined that the existing San Onofre Unit 2 and 3 steam generators may not enable continued reliable operation of the units beyond their scheduled refueling outages in 2009–2010. SCE currently estimates that the cost of replacing the steam generators would be about $680 million, of which SCE's 75% share would be about $510 million. On February 27, 2004, SCE asked the CPUC to issue a decision by July 2005 finding that it is reasonable for SCE to replace the San Onofre Unit 2 and 3 steam generators and establishing appropriate ratemaking for the replacement costs. In its application, SCE stated that the San Onofre operating agreement requires unanimous approval of all co-owners for the costs of the steam generator replacement to be included in the capital budget for Units 2 and 3 and, therefore, SCE must have the approval of its co-owners to go forward as planned, which approval currently is lacking. Because SCE will need to enter into commitments in 2004 to obtain timely delivery of replacement steam generators, SCE also asked the CPUC to create a memorandum account by September 2004 for SCE to recover initial costs of up to $50 million if the replacement project ultimately is not approved by the CPUC or co-owner approval is not obtained. If the CPUC finds investment in the steam generators to be reasonable and cost effective and the steam generator replacement takes place, SCE's investment should be reflected in retail rates for recovery over the remaining useful life of the plants. SCE currently does not expect that it would proceed with replacement of the San Onofre Units 2 and 3 steam generators without CPUC approval of reasonable cost recovery.

Palo Verde Steam Generators

The steam generators at the Palo Verde Nuclear Generating Station (Palo Verde), in which SCE owns a 15.8% interest, have the same design and material properties as the San Onofre units. During 2003, the Palo Verde Unit 2 steam generators were replaced. In addition, the Palo Verde owners have approved the manufacture of two additional sets of steam generators for installation in Units 1 and 3. The Palo Verde owners expect that these steam generators will be installed in Units 1 and 3 in the 2005 to 2008 time frame. SCE's share of the costs of manufacturing and installing all the replacement steam generators at Palo Verde is estimated to be about $110 million; SCE plans to seek recovery of that amount through the rate-making process.

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 Statement of Cash Flows.

Results of Operations

Earnings from Continuing Operations

SCE earnings from continuing operations in 2003 were $882 million, compared to earnings of $1.2 billion in 2002 and earnings of $2.4 billion in 2001. SCE's 2002 earnings included a $480 million benefit related to the implementation of the CPUC URG decision. SCE's 2001 earnings included a $2.1 billion (after tax) benefit resulting from the reestablishment of procurement-related regulatory assets and liabilities as a result of the PROACT resolution and recovery of $178 million (after tax) of previously written off generation-related regulatory assets, partially offset by $328 million (after tax) of net undercollected transition costs incurred between January and August 2001. Excluding the $480 million benefit in 2002 and the net $2.0 billion benefit in 2001, SCE's earnings from continuing operations were $767 million in 2002 and $408 million in 2001. The $115 million increase between 2003 and 2002 results from the net effect of the resolution of several regulatory proceedings in 2003 and 2002. The 2003 proceedings include the CPUC decision on the allocation of certain costs between state and federal regulatory jurisdictions, tax impacts from the FERC rate case, and the final disposition of the PROACT which had been created to record the recovery of SCE's procurement-related obligations. The positive effects of these factors on 2003 earnings were partially offset by the implementation in 2002 of the CPUC's URG decision and PBR rewards received in 2002. SCE's results also included higher depreciation expense and lower net interest income, partially offset by higher FERC and PBR revenue. The $359 million increase between 2002 and 2001 primarily reflects increased revenue resulting from the CPUC's 2002 decision in SCE's PBR proceeding, increased earnings from SCE's larger rate base in 2002 compared to 2001, lower interest expense, PBR rewards from prior years and increased income from San Onofre Nuclear Generating Station (San Onofre) Units 2 and 3. The increase was partially offset by higher operating and maintenance expense.

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

Operating Revenue

SCE's retail sales represented approximately 91%, 96% and 94% of operating revenue in 2003, 2002, and 2001, respectively. Due to warmer weather during the summer months, operating revenue during the third quarter of each year is significantly higher than other quarters.

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

In millions Year ended December 31,	2003 vs. 2002	2002 vs. 2001
Operating revenue		
Rate changes (including surcharges)	$ (677)	$ 563
Direct access credit	471	(604)
Sales volume changes	(60)	696
Sales for resale	394	(11)
Other	20	(64)
Total	$ 148	$ 580

Total operating revenue increased by $148 million in 2003 (as shown in the table above). The reduction in operating revenue due to rate changes resulted from the implementation of a CPUC-approved customer rate-reduction plan effective August 1, 2003, partially offset by the recognition of revenue from the CPUC-authorized temporary surcharge collected in 2002, used to recover costs incurred in 2003 (see "Regulatory Matters—Generation and Power Procurement—Temporary Surcharges"). The increase in operating revenue due to direct access credits resulted from a net 1¢-per-kWh decrease in credits given to direct access customers. The reduction in electric revenue resulting from changes in sales volume was mainly due to an increase in the amount allocated to the CDWR for bond and direct access exit fees (see discussion below), partially offset by an increase in kWh sold due to warmer weather in 2003 as compared to 2002. Sales for resale revenue increased due to a greater amount of excess energy at SCE in 2003 as compared to 2002. As a result of CDWR contracts allocated to SCE, excess energy from SCE sources may exist at certain times and is resold in the energy markets.

Operating revenue increased by $580 million in 2002 as compared to 2001 (as shown in the table above). The increase in operating revenue due to rate changes resulted from a 3¢-per-kWh surcharge authorized by the CPUC as of March 27, 2001. The decrease in operating revenue due to direct access credits resulted from an increase in credits given to direct access customers due to a significant increase in the number of direct access customers. The increase in operating revenue resulting from changes in sales volume was primarily due to SCE providing its customers with a greater volume of energy generated from its own generating plants and power-purchase contracts, rather than the CDWR purchasing power on behalf of SCE's customers.

Amounts SCE bills and collects from its customers for electric power purchased and sold by the CDWR to SCE's customers (beginning January 17, 2001), CDWR bond-related costs (beginning November 15, 2002) and direct access exit fees (beginning January 1, 2003) are remitted to the CDWR and are not recognized as revenue by SCE. These amounts were $1.7 billion, $1.4 billion, and $2.0 billion for the years ended December 31, 2003, 2002, and 2001, respectively.

Operating Expenses

Fuel expense increased in 2002 primarily due to fuel related costs SCE related to a payment received under a settlement agreement with Peabody associated with Mohave.

Purchased-power expense increased in 2003 and decreased in 2002. The 2003 increase was mainly due to higher expenses resulting from SCE's resumption of power procurement on January 1, 2003. The higher expenses resulted from an increase in the number of bilateral contracts entered into during 2003 and an increase in energy purchased in 2003. The increase also includes higher expenses related to power purchased from QFs, mainly due to higher spot natural gas prices in 2003 as compared to 2002. The 2002 decrease resulted primarily from lower expenses related to power purchased from QFs, bilateral contracts and interutility contracts, mainly due to lower spot natural gas prices in 2002 as compared to 2001. In addition, the decrease reflects the absence of PX/ISO purchased-power expense after mid-January 2001.

Federal law and CPUC orders required SCE to enter into contracts to purchase power from QFs at CPUC-mandated prices. These contracts expire on various dates through 2025. Energy payments to gas-fired cogeneration QFs are generally tied to spot natural gas prices. Effective May 2002, energy payments for most renewable QFs were converted to a fixed price of 5.37¢-per-kWh, compared with an average of 3.1¢-per-kWh during the period of January and April 2002. During 2003, spot natural gas prices were higher compared to the same period in 2002. During 2002, spot natural gas prices were significantly lower than the same periods in 2001.

Provisions for regulatory adjustment clauses – net decreased in 2003 and increased in 2002. The 2003 decrease was mainly due to lower overcollections used to recover the PROACT balance, the implementation of the CPUC-authorized customer rate-reduction plan, a net increase in energy procurement costs and favorable resolution of several regulatory proceedings. The 2003 proceedings include the CPUC decision on the allocation of certain costs between state and federal regulatory jurisdictions and the final disposition of the PROACT. The decrease was partially offset by the implementation of the CPUC decision related to URG and the PBR mechanism, as well as the impact of other regulatory actions recorded in 2002. The 2002 increase was primarily due to the establishment of the PROACT regulatory asset in 2001, overcollections used to recover the PROACT balance and revenue collected to recover the rate reduction bond regulatory asset, partially offset by the impact of SCE's implementation of the CPUC decision related to URG and the PBR mechanism, as well as the impact of other regulatory actions.

As a result of the URG decision received in 2002, SCE reestablished regulatory assets previously written off (approximately $1.1 billion) related to its nuclear plant investments, purchased-power settlements and flow-through taxes, and decreased the PROACT balance by $256 million, all retroactive to January 1, 2002. The impact of the URG decision is reflected in the 2002 financial statements as a credit (decrease) to the provisions for regulatory adjustment clauses of $644 million, partially offset by an increase in deferred income tax expense of $164 million, for a net credit to earnings of $480 million. As a result of the CPUC decision that modified the PBR mechanism, SCE recorded a $136 million credit (decrease) to the provisions for regulatory adjustment clauses in the second quarter of 2002, to reflect undercollections in CPUC-authorized revenue resulting from changes in retail rates.

Other operating and maintenance expense increase in 2003 was mainly due to higher health-care costs, higher spending on certain CPUC-authorized programs, higher transmission access charges and costs incurred in 2003 related to the removal of dead, dying and diseased trees and vegetation associated with the bark beetle infestation (see "Regulatory Matters—Other Regulatory Matters—Catastrophic Event Memorandum Account"). Other operation and maintenance expense increase in 2002 was primarily due to the San Onofre Unit 2 refueling outage in 2002, increases in transmission and distribution maintenance and inspection activities, and temporary cost containment efforts that took place in 2001. The 2002 increases were partially offset by lower expenses related to balancing accounts.

Depreciation, decommissioning and amortization expense increased in both 2003 and 2002. The 2003 increase was mainly due to an increase in depreciation expense associated with additions to transmission and distribution assets and an increase in nuclear decommissioning expense. The 2003 increase was

partially offset by a change in the amortization period for San Onofre recorded in the third quarter of 2002 based on the implementation of a CPUC decision. The increase in 2002 was mainly due to an increase in depreciation expense associated with SCE's additions to transmission and distribution assets and an increase in SCE's nuclear decommissioning expense. A 1994 CPUC decision allowed SCE to accelerate the recovery of its nuclear-related assets while deferring the recovery of its distribution-related assets for the same amount. Beginning in January 2002, the CPUC approved the commencement of recovery of SCE's deferred distribution assets. In addition, the increases reflect amortization expense on the nuclear regulatory asset reestablished during second quarter 2002 based on the URG decision.

Other Income and Deductions

Interest and dividend income decreased in 2003 and increased in 2002. The 2003 decrease was mainly due to lower interest income on the PROACT balance as well as lower interest income from lower average cash balances, compared to the same period in 2002. The 2002 increase was mainly due to the interest income earned on the PROACT balance. The 2002 increase was partially offset by lower interest income due to lower average cash balances and lower interest rates during 2002, as compared to 2001.

Other nonoperating income decreased slightly in 2003 and increased in 2002. The 2003 decrease was mainly due to property condemnation settlements received in 2002, with no comparable settlements received in 2003, almost entirely offset by the recognition of 2000 and 2001 Palo Verde performance rewards approved by the CPUC during 2003. The 2002 increase was primarily due to property condemnation settlements received, partially offset by PBR incentive awards for 1999 and 2000, which were approved by the CPUC and recorded in 2001.

Interest expense – net of amounts capitalized decreased in both 2003 and 2002. The 2003 decrease was due to lower interest expense at SCE due to the accrual of interest in 2002 related to the 2001 and early 2002 suspension of payments for purchased power (these suspended payments were paid in March 2002), as well as lower interest expense on long-term debt resulting from the early retirement of debt. Interest expense – net in 2003 reflects a change in the classification of dividend payments on preferred securities to interest expense – net from dividends on preferred securities. Effective July 1, 2003, dividend payments on preferred securities subject to mandatory redemption are included as interest expense based on the adoption of a new accounting standard. The new standard did not allow for prior period restatements, therefore dividends on preferred securities subject to mandatory redemption for the first six months of 2003 are not included in interest expense – net of amounts capitalized in the consolidated statements of income. The 2002 decrease is mainly due to lower short-term debt balances in 2002, compared to 2001 and lower interest expense related to the suspension of payments for purchased power during 2001, which were subsequently paid in early 2002. The 2002 decrease was partially offset by an increase in interest expense on long-term debt due to higher long-term debt balances in 2002, compared to 2001.

Other nonoperating deductions increased in 2003 and decreased in 2002. The variance in both 2003 and 2002 was primarily due to the reversal of accruals for regulatory matters in 2002.

Income Taxes

Income taxes decreased in both 2003 and 2002. The 2003 and 2002 decrease was primarily due to reductions in pre-tax income and the favorable resolution of tax audit issues. The 2003 decrease also resulted from the favorable resolution of a FERC rate case. The 2002 decrease also resulted from the reestablishment of tax-related regulatory assets upon implementation of the URG decision.

SCE's federal and state statutory tax rate was 40.551% for all years presented. The lower effective tax rate of 30.5% realized in 2003 was primarily due to the resolution of a FERC rate case and recording the benefit of favorable resolution of tax audit issues. The lower effective tax rate of 34% realized in 2002 was primarily due to the reestablishment of tax-related regulatory assets upon implementation of the URG decision as well as favorable resolution of tax audit issues.

Earnings from Discontinued Operations

SCE's earnings from discontinued operations in 2003, included a $44 million (after-tax) gain on the sale of SCE's fuel oil pipeline business and operating results of $6 million.

Historical Cash Flow Analysis

Cash Flows from Operating Activities

Net cash provided by operating activities was $2.7 billion in 2003, $631 million in 2002 and $3.3 billion in 2001. The 2003 increase was mainly due to the March 2002 repayment of past-due obligations, as well as the timing of cash receipts and disbursements related to working capital items. The 2002 decrease in cash provided by operating activities was mainly due to the March 2002 repayment of past-due obligations, partially offset by higher overcollections used to recover regulatory assets resulting from the CPUC-approved surcharges (1¢ per kWh in January 2001 and 3¢ per kWh in June 2001).

Cash used by operating activities from discontinued operations in 2003 primarily reflects operating activities at SCE's fuel oil pipeline business.

Cash Flows from Financing Activities

SCE's short-term debt is normally used to finance procurement-related obligations. Long-term debt is used mainly to finance the utility's rate base. External financings are influenced by market conditions and other factors.

SCE's financing activities during 2003 included an exchange offer of $966 million of 8.95% variable rate notes due November 2003 for $966 million of new series first and refunding mortgage bonds due February 2007. In addition, during 2003, SCE repaid $125 million of its 6.25% bonds, the outstanding balance of $300 million of a $600 million one-year term loan due March 3, 2003, $300 million on its revolving line of credit, and $700 million of a term loan due March 2005. The $700 million term loan was retired with a cash payment of $500 million and $200 million drawn on a $700 million credit facility that expires in 2006. SCE's 2003 financing activities also include a dividend payment of $945 million of equity to Edison International.

During the first quarter of 2002, SCE paid $531 million of matured commercial paper and remarketed $196 million of the $550 million of pollution-control bonds repurchased during December 2000 and early 2001. Also during the first quarter of 2002, SCE replaced the $1.65 billion credit facility with a $1.6 billion financing and made a payment of $50 million to retire the entire credit facility. Throughout the year, SCE paid approximately $1.2 billion of maturing long-term debt. The $1.6 billion financing included a $600 million, one-year term loan due March 3, 2003. SCE prepaid $300 million of this loan in August 2002.

In December 1997, $2.5 billion of rate reduction notes were issued on behalf of SCE by SCE Funding LLC, a special purpose entity. These notes were issued to finance the 10% rate reduction mandated by state law. The proceeds of the rate reduction notes were used by SCE Funding LLC to purchase from

SCE an enforceable right known as transition property. Transition property is a current property right created by the electric industry restructuring legislation and a financing order of the CPUC and consists generally of the right to be paid a specified amount from nonbypassable rates charged to residential and small commercial customers. The rate reduction notes are being repaid over 10 years through these nonbypassable residential and small commercial customer rates, which constitute the transition property purchased by SCE Funding LLC. The remaining series of outstanding rate reduction notes have scheduled maturities through 2007, with interest rates ranging from 6.38% to 6.42%. The notes are collateralized by the transition property and are not collateralized by, or payable from, assets of SCE or Edison International. SCE used the proceeds from the sale of the transition property to retire debt and equity securities. Although, as required by accounting principles generally accepted in the United States, SCE Funding LLC is consolidated with SCE and the rate reduction notes are shown as long-term debt in the consolidated financial statements, SCE Funding LLC is legally separate from SCE. The assets of SCE Funding LLC are not available to creditors of SCE or Edison International and the transition property is legally not an asset of SCE or Edison International.

Cash Flows from Investing Activities

Cash flows from investing activities are affected by additions to property and plant and funding of nuclear decommissioning trusts.

Additions to SCE's property and plant during 2003 were approximately $1.2 billion, primarily for transmission and distribution assets. Additions to SCE's property and plant during 2002 were approximately $1.0 billion, primarily for transmission and distribution assets.

Investing cash flows from discontinued operations in 2003 represents the proceeds received from SCE's sale of its fuel oil pipeline business.

Nuclear decommissioning costs are recovered in utility rates. These costs are expected to be funded from independent decommissioning trusts that receive SCE contributions of approximately $32 million per year. The fair value of decommissioning SCE's nuclear power facilities is $2.1 billion as of December 31, 2003, based on site-specific studies performed in 2001 for San Onofre and Palo Verde. As of December 31, 2003, the decommissioning trust balance was $2.5 billion. The CPUC has set certain restrictions related to the investments of these trusts. Contributions to the decommissioning trusts are reviewed every three years by the CPUC. The contributions are determined from an analysis of estimated decommissioning costs, the current value of trust assets and long-term forecasts of cost escalation and after-tax return on trust investments. Favorable or unfavorable investment performance in a period will not change the amount of contributions for that period. However, trust performance for the three years leading up to a CPUC review proceeding will provide input into future contributions. SCE's costs to decommission San Onofre Unit 1 are paid from the nuclear decommissioning trust funds. These withdrawals from the decommissioning trusts are netted with the contributions to the trust funds in the Consolidated Statements of Cash Flows.

DISPOSITION AND DISCONTINUED OPERATIONS

On July 10, 2003, the CPUC approved SCE's sale of certain oil storage and pipeline facilities to Pacific Terminals LLC for $158 million. In third quarter 2003, SCE recorded a $44 million after-tax gain to shareholders. In accordance with an accounting standard related to the impairment and disposal of long-lived assets, this oil storage and pipeline facilities unit's results have been accounted for as a discontinued operation in the 2003 financial statements. Due to immateriality, the results of this unit for prior years have not been restated and are reflected as part of continuing operations.

ACQUISITION

On July 17, 2003, SCE signed an option agreement with Sequoia Generating LLC, a subsidiary of InterGen, to acquire Mountainview Power Company LLC, the owner of a new 1,054-megawatt, combined-cycle, natural gas-fired power plant currently being developed in Redlands, California. Mountainview Power Company LLC would sell all the output of the power plant to SCE pursuant to a 30-year tolling power-purchase agreement. The power-purchase agreement would be a cost-based contract providing for recovery of investment, fixed and variable costs, and a regulated rate of return, over the 30-year life of the contract. On December 18, 2003, the CPUC approved the Mountainview power-purchase agreement, subject to SCE receiving a FERC decision approving the agreement without any modifications that would have potential rate impacts. On February 25, 2004, the FERC granted conditional approval of the Mountainview power-purchase agreement. On March 1, 2004, a CPUC administrative law judge issued a proposed decision that would accept the conditions in the FERC approval of the power-purchase agreement. The matter is scheduled to be considered by the CPUC at its meeting on March 16, 2004. On February 28, 2004, SCE exercised its option to purchase Mountainview Power LLC. SCE currently anticipates that it will close the purchase before the end of March 2004 and recommence construction of the project immediately thereafter. SCE estimates that the project will be completed in March 2006 at a cost of approximately $600 million, excluding financing costs. SCE expects to finance the capital costs of the project with debt and equity at the utility level consistent with its authorized capital structure.

CRITICAL ACCOUNTING POLICIES

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

Asset Impairment

SCE evaluates long-lived assets whenever indicators of potential impairment exist. Accounting standards require that if the undiscounted expected future cash flow from a company's assets or group of assets (without interest charges) is less than its carrying value, an asset impairment must be recognized in the financial statements. The amount of impairment is determined by the difference between the carrying amount and fair value of the asset.

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

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

Income Taxes

The accounting standard for income taxes requires the asset and liability approach for financial accounting and reporting for deferred income taxes. SCE provides deferred income taxes for all significant income tax temporary differences.

As part of the process of preparing its consolidated financial statements, SCE is required to estimate its income taxes in each of the jurisdictions in which it operates. This process involves estimating actual current tax expense together with assessing temporary differences resulting from differing treatment of items, such as depreciation, for tax and accounting purposes. These differences result in deferred tax assets and liabilities, which are included within SCE's consolidated balance sheet. Management continually evaluates its income tax exposures and provides for allowances and/or reserves as deemed necessary.

Pensions and Postretirement Benefits Other Than Pensions

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

The discount rate enables SCE to state expected future cash flows at a present value on the measurement date. At the December 31, 2003 measurement date, SCE used a discount rate of 6% for pensions and 6.25% for postretirement benefits other than pensions (PBOP) that represented the market interest rate for high-quality fixed income investments.

To determine the expected long-term rate of return on pension plan assets, current and expected asset allocations are considered, as well as historical and expected returns on plan assets. The expected rate of return on plan assets was 8.5% for pensions and 8.2% for PBOP. A portion of PBOP trust asset returns are subject to taxation, so the 8.2% figure above is determined on an after-tax basis. Actual returns on pension plan assets were 27.6%, 7.3%, and 10.8% for the one-year, five-year and ten-year periods ended December 31, 2003, respectively. Actual returns on PBOP plan assets were 26%, 2.2%, and 9.1% over the same periods. Accounting principles provide that differences between expected and actual returns are recognized over the average future service of employees.

At December 31, 2003, SCE's pension plans included $2.8 billion in projected benefit obligation (PBO), $2.4 billion in accumulated benefit obligation (ABO) and $2.8 billion in plan assets. A 1% decrease in the discount rate would increase the PBO by $205 million, and a 1% increase would decrease the PBO by $191 million, with corresponding changes in the ABO. A 1% decrease in the expected rate of return on plan assets would increase pension expense by $22 million.

SCE records pension expense equal to the amount funded to the trusts, as calculated using an actuarial method required for ratemaking 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 ratemaking methods and pension expense or income calculated in accordance with accounting standards, is accumulated in a regulatory asset or liability, and will, over time, be recovered from or returned to customers. As of December 31, 2003, this cumulative difference amounted to a regulatory liability of $140 million, meaning that the ratemaking method has resulted in recognizing

$140 million more in expense than the accounting method since implementation of the pension accounting standard in 1987.

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

See "Other Developments—Employee Compensation and Benefit Plans" for information related to SCE's cash balance pension plan.

At December 31, 2003, SCE's PBOP plan included $2.1 billion in PBO and $1.4 billion in plan assets. Total expense for these plans was $117 million for 2003. Increasing the health care cost trend rate by one percentage point would increase the accumulated obligation as of December 31, 2003 by $305 million and annual aggregate service and interest costs by $27 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated obligation as of December 31, 2003 by $248 million and annual aggregate service and interest costs by $22 million.

On December 8, 2003, President Bush signed the Medicare Prescription Drug, Improvement and Modernization Act of 2003. The Act authorized a federal subsidy to be provided to plan sponsors for certain prescription drug benefits under Medicare. SCE has elected to defer accounting for the effects of the Act until the earlier of the issuance of guidance by the Financial Accounting Standards Board on how to account for the Act, or the remeasurement of plan assets and obligations subsequent to January 31, 2004. Accordingly, any measures of the accumulated postretirement benefit obligation or net periodic postretirement benefit expense above do not reflect the effects of the Act on SCE's plan. Specific authoritative guidance on the accounting for the federal subsidy is pending and that guidance, when issued, could require SCE to restate previously reported information.

Rate Regulated Enterprises

SCE applies accounting principles for rate-regulated enterprises to the portion of its operations, in which regulators set rates at levels intended to recover the estimated costs of providing service, plus a return on capital. Due to timing and other differences in the collection of revenue, these principles allow an incurred cost that would otherwise be charged to expense by a nonregulated entity to be capitalized as a regulatory asset if it is probable that the cost is recoverable through future rates and conversely allow creation of a regulatory liability for probable future costs collected through rates in advance. SCE's management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as the current regulatory environment, the issuance of rate orders on recovery of the specific incurred cost or a similar incurred cost to SCE or other rate-regulated entities in California, and assurances from the regulator (as well as its primary intervenor groups) that the incurred cost will be treated as an allowable cost (and not challenged) for rate-making purposes. Because current rates include the recovery of existing regulatory assets and settlement of regulatory liabilities, and rates in effect are expected to allow SCE to earn a reasonable rate of return, management believes that existing regulatory assets and liabilities are probable of recovery. This determination reflects the current political and regulatory climate in California and is subject to change in the future. If future recovery of costs ceases to be probable, all or part of the regulatory assets and liabilities would have to be written off against current period earnings. At December 31, 2003, the Consolidated Balance Sheets included regulatory assets, less regulatory liabilities, of $234 million. Management continually evaluates the anticipated recovery of regulatory assets, liabilities, and revenue subject to refund and provides for allowances and/or reserves as deemed necessary.

SCE applied judgment in the use of the above principles when it: (1) created the $3.6 billion PROACT regulatory asset in the fourth quarter of 2001; (2) restored $480 million (after-tax) of generation-related regulatory assets based on the URG decision in the second quarter of 2002; and (3) established a $61 million regulatory asset related to the impaired Mohave in the fourth quarter of 2002. In all instances, SCE recorded corresponding credits to earnings upon concluding that such incurred costs were probable of recovery in the future. See further discussion in "Results of Operations and Historical Cash Flow Analysis—Results of Operations—Earnings" and "Regulatory Matters—Generation and Power Procurement—PROACT Regulatory Asset," "—Utility-Retained Generation," and "—Mohave Generating Station and Related Proceedings" sections.

NEW ACCOUNTING PRINCIPLES

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

SCE's impacts of adopting this standard were:

- SCE adjusted its nuclear decommissioning obligation to reflect the fair value of decommissioning its nuclear power facilities. SCE also recognized AROs associated with the decommissioning of other coal-fired generation assets. Fair values were determined based on site-specific studies conducted by third-party contractors.

- At December 31, 2002, SCE had accrued $2.3 billion to decommission its nuclear facilities and $12 million to decommission its share of a coal-fired generating plant, under accounting principles in effect at that time. Of these amounts, $298 million to decommission its inactive nuclear facility was recorded in other long-term liabilities, and the remaining $2.0 billion was recorded as a component of the accumulated provision for depreciation and decommissioning on the consolidated balance sheets in the 2002 Annual Report.

- As of January 1, 2003, SCE reversed the $2.3 billion it had previously recorded for decommissioning, recorded the fair value of its AROs of approximately $2.02 billion in the deferred credits and other liabilities section of the balance sheet, and increased its unamortized nuclear investment by $303 million. The cumulative effect of a change in accounting principle from unrecognized accretion expense and adjustments to depreciation, decommissioning and amortization expense recorded to date was a $354 million after-tax gain, which under accounting standards for rate-regulated enterprises was deferred as a regulatory liability, partially offset by a $235 million deferred tax asset, as of January 1, 2003. Accretion expense on the ARO ($128 million) and depreciation expense on the new asset ($15 million) resulting from the application of the new standard in 2003 reduced the regulatory liability, with no impact on earnings. SCE's ARO liability account increased from $2.02 billion to $2.08 billion in 2003, with the $128 million in accretion partially offset by $68 million in expenditures related to the decommissioning of its inactive nuclear facility. As of December 31, 2003, SCE's ARO for its nuclear

facilities totaled approximately $2.07 billion and its nuclear decommissioning trust assets had a fair value of $2.5 billion. If the new standard had been in place on January 1, 2002, SCE's ARO as of that date would have been $1.98 billion. If the standard had been applied retroactively for the years ended December 31, 2002 and 2001, it would not have had any impact on SCE's results of operations.

- SCE has collected in rates amounts for the future costs of removal and decommissioning of assets, and has historically recorded these amounts in accumulated provision for depreciation. However, in accordance with recent Securities and Exchange Commission accounting guidance, the amounts accrued in accumulated provision for depreciation for decommissioning and costs of removal were reclassified to regulatory liabilities as of December 31, 2002. The cost of removal amounts collected for assets not legally required to be removed remain in regulatory liabilities as of December 31, 2003. Amounts collected through rates for cost of removal of plant assets not considered to be legal obligations ($2.02 billion at December 31, 2003 and $1.92 billion at December 31, 2002) are included in regulatory liabilities.

Effective July 1, 2003, SCE adopted a new accounting standard, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity, which required issuers to classify certain freestanding financial instruments as liabilities. These freestanding liabilities include mandatorily redeemable financial instruments, obligations to repurchase the issuer's equity shares by transferring assets and certain obligations to issue a variable number of shares. Effective July 1, 2003, SCE reclassified its preferred stock subject to mandatory redemption to the liabilities section of its consolidated balance sheet. This item was previously classified between liabilities and equity. In addition, effective July 1, 2003, dividend payments on this instrument are included in interest expense – net of amounts capitalized on SCE's consolidated statements of income. Prior period financial statements are not permitted to be restated for these changes. Therefore, upon adoption there was no cumulative impact incurred due to this accounting change.

In May 2003, the Emerging Issues Task Force (EITF) reached a consensus on Determining Whether an Arrangement Contains a Lease, which provides guidance on how to determine whether an arrangement contains a lease that is within the scope of the standard, Accounting for Leases. A lease is defined as an agreement conveying the right to use property, plant, or equipment (land and/or depreciable assets) usually for a stated period of time. The guidance issued by the EITF could affect the classification of a power sales agreement that meets specific criteria, such as a power sales agreement for substantially all of the output from a power plant to one customer. If a power sales agreement meets the guidance issued by the EITF, it would be accounted for as a lease subject to the lease accounting standard. The consensus is effective prospectively for arrangements entered into or modified after June 30, 2003. The consensus had no impact on SCE's financial statements as of December 31, 2003.

In December 2003, the Financial Accounting Standards Board issued a revision to an accounting Interpretation (originally issued in January 2003), Consolidation of Variable Interest Entities (VIEs). The primary objective of the Interpretation is to provide guidance on the identification of, and financial reporting for, so-called "variable interest entities," where control may be achieved through means other than voting rights. Under the Interpretation, the enterprise that, using a discounted cash flow method, is expected to absorb or receive the majority of a VIE's expected losses or residual returns, or both, must consolidate the VIE. This Interpretation is effective for special purpose entities, as defined by accounting principles generally accepted in the United States, as of December 31, 2003, and all other entities as of March 31, 2004.

Guidance related to implementation of this Interpretation is evolving. SCE has over 240 long-term power-purchase contracts with independent power producers that own QFs. SCE was required under federal law to sign such contracts, which typically require SCE to purchase 100% of the power produced

by these facilities, and the CPUC controls the terms and pricing. Under this accounting Interpretation, SCE could be required to consolidate some or all of the entities that hold these contracts depending on 1) whether these power generators are considered to be VIEs, and 2) whether SCE is considered to be the consolidating entity. These entities are not legally obligated to provide the financial information to SCE, which would be required to determine whether SCE must consolidate these entities. SCE does not know which, if any, of these entities will provide the necessary information. SCE has no investment in, nor obligation to provide support to, these entities other than its requirement to make payment as required by the power-purchase agreements. However, if SCE is required to consolidate these entities, it may be required to recognize losses to the extent of any negative equity. These losses, if any, would not affect SCE's liquidity. Edison Mission Energy, a wholly owned subsidiary of Edison International, has 49% to 50% ownership in four QF partnerships that have long-term power sales contracts with SCE. Edison Mission Energy accounts for these projects using the equity method. If long-term power-purchase contracts are deemed to be variable interests, and due to the related-party nature of this transaction, it is likely that these four QFs could be consolidated by either Edison Mission Energy or SCE.

COMMITMENTS

SCE's commitments for the years 2004 through 2008 and thereafter are estimated below:

In millions	2004	2005	2006	2007	2008	Thereafter
Long-term debt maturities and sinking fund requirements	$ 371	$ 442	$ 446	$ 1,251	$ —	$1,982
Estimated noncancelable lease payments	13	10	7	6	4	8
Fuel supply contract payments	182	126	58	66	51	495
Purchased-power capacity payments	682	663	637	637	444	3,621
Unconditional purchase obligations	10	10	10	10	10	89
Preferred securities redemption requirements	9	9	9	69	54	—

SCE's projected construction expenditures for 2004 are $1.9 billion, including the investment and projected construction expenditures for the Mountainview project (see "Acquisition"). These expenditures are planned to be financed primarily through cash generated from operations and borrowings.

Leases

SCE has operating leases, primarily for vehicles, with varying terms, provisions and expiration dates.

Fuel Supply Contracts

SCE has fuel supply contracts which require payment only if the fuel is made available for purchase. Certain SCE gas and coal fuel contracts require payment of certain fixed charges whether or not gas or coal is delivered. In addition, fuel supply contract payments include payments for nuclear fuel commitments.

Power Purchase Contracts

SCE has power-purchase contracts with certain QFs (cogenerators and small power producers) and other utilities. These contracts provide for capacity payments if a facility meets certain performance obligations and energy payments based on actual power supplied to SCE. There are no requirements to

make debt-service payments. In an effort to replace higher-cost contract payments with lower-cost replacement power, SCE has entered into purchased-power settlements to end its contract obligations with certain QFs. The settlements are reported as power purchase contracts on the balance sheets. In addition, SCE entered into bilateral forward power contracts during 2003, which contain capacity payment provisions.

Unconditional Purchase Obligations

SCE has unconditional purchase obligations for part of a power plant's generating output, as well as firm transmission service from another utility. Minimum payments are based, in part, on the debt-service requirements of the provider, whether or not the plant or transmission line is operable. The purchased-power contract is expected to provide approximately 5% of current or estimated future operating capacity, and is reported as power-purchase contracts (approximately $28 million).

Other Commitments

SCE's expected contributions (all by the employer) for its pension and PBOP plans are approximately $33 million and $100 million, respectively, for the year ended December 31, 2004. These amounts are subject to change based on, among other things, the limits established for federal tax deductibility (pension plan) and the impact of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (PBOP plan).

Responsibility for Financial Reporting

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

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

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

As a further measure to assure the ongoing objectivity of financial information, the Audit Committee of the Board of Directors, which is composed of outside directors, meets periodically, both jointly and separately, with management, the independent auditors and internal auditors, who have unrestricted access to the committee. The committee annually appoints a firm of independent auditors (who are ultimately responsible to the committee) to conduct audits of SCE's financial statements; considers the independence of such firm and the overall adequacy of the audit scope and SCE's systems of internal control; reviews financial reporting issues; and is advised of management's actions regarding financial reporting and internal control matters.

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

/s/ Thomas M. Noonan

Thomas M. Noonan
Vice President
and Controller

/s/ Alan J. Fohrer

Alan J. Fohrer
Chief Executive Officer

March 10, 2004

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, cash flows and changes in common shareholder's equity present fairly, in all material respects, the financial position of Southern California Edison Company and its subsidiaries at December 31, 2003 and 2002, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion. The financial statements of the Company for the year ended December 31, 2001 were audited by other independent accountants who have ceased operations. Those independent accountants expressed an unqualified opinion on the financial statements in their report dated March 25, 2002.

As discussed in Note 1 to the consolidated financial statements, the Company changed the manner in which it accounts for asset retirement costs as of January 1, 2003, and financial instruments with characteristics of both debt and equity as of July 1, 2003.

/s/ PricewaterhouseCoopers LLP

Los Angeles, California
March 10, 2004

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

To Southern California Edison Company:

We have audited the accompanying consolidated balance sheets of Southern California Edison Company (SCE, a California corporation) and its subsidiaries as of December 31, 2001, and 2000, and the related consolidated statements of income (loss), comprehensive income (loss), cash flows and changes in common shareholder's equity for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of SCE's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of SCE and its subsidiaries as of December 31, 2001, and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

ARTHUR ANDERSEN LLP

Los Angeles, California
March 25, 2002

Consolidated Statements of Income

Southern California Edison Company

In millions Year ended December 31,	2003	2002	2001
Operating revenue	$ 8,854	$ 8,706	$ 8,126
Fuel	235	243	212
Purchased power	2,786	2,016	3,770
Provisions for regulatory adjustment clauses – net	1,138	1,502	(3,028)
Other operation and maintenance	2,054	1,926	1,771
Depreciation, decommissioning and amortization	882	780	681
Property and other taxes	168	117	112
Net gain on sale of utility plant	(5)	(5)	(9)
Total operating expenses	7,258	6,579	3,509
Operating income	1,596	2,127	4,617
Interest and dividend income	100	262	215
Other nonoperating income	72	75	57
Interest expense – net of amounts capitalized	(457)	(584)	(785)
Other nonoperating deductions	(41)	9	(38)
Income from continuing operations before tax	1,270	1,889	4,066
Income tax	388	642	1,658
Income from continuing operations	882	1,247	2,408
Income from discontinued operations	82	—	—
Income tax on discontinued operations	32	—	—
Net income	932	1,247	2,408
Dividends on preferred stock	10	19	22
Net income available for common stock	$ 922	$ 1,228	$ 2,386

Consolidated Statements of Comprehensive Income

In millions Year ended December 31,	2003	2002	2001
Net income	$ 932	$ 1,247	$ 2,408
Other comprehensive income, net of tax:			
Minimum pension liability adjustment	(4)	(5)	—
Cumulative effect of change in accounting for derivatives	—	—	398
Unrealized gain (loss) on and amortization of cash flow hedges	1	11	(420)
Comprehensive income	$ 929	$ 1,253	$ 2,386

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

Consolidated Balance Sheets

In millions December 31,	2003	2002
ASSETS		
Cash and equivalents	$ 95	$ 992
Restricted cash	66	47
Receivables, less allowances of $30 and $36 for uncollectible accounts at respective dates	751	767
Accrued unbilled revenue	408	437
Fuel inventory	10	12
Materials and supplies, at average cost	168	153
Accumulated deferred income taxes – net	508	299
Regulatory assets – net	—	459
Prepayments and other current assets	58	57
Total current assets	2,064	3,223
Nonutility property – less accumulated provision for depreciation of $24 and $15 at respective dates	116	103
Nuclear decommissioning trusts	2,530	2,210
Other investments	153	235
Total investments and other assets	2,799	2,548
Utility plant, at original cost:		
Transmission and distribution	14,861	14,202
Generation	1,371	1,348
Accumulated provision for depreciation	(4,386)	(4,057)
Construction work in progress	600	529
Nuclear fuel, at amortized cost	141	153
Total utility plant	12,587	12,175
Regulatory assets – net	510	—
Other deferred charges	506	629
Total deferred charges	1,016	629
Assets of discontinued operations	—	62
Total assets	$ 18,466	$ 18,637

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

In millions, except share amounts December 31,	2003	2002
LIABILITIES AND SHAREHOLDERS' EQUITY		
Short-term debt	$ 200	$ —
Long-term debt due within one year	371	1,671
Preferred stock to be redeemed within one year	9	9
Accounts payable	891	665
Accrued taxes	556	699
Regulatory liabilities – net	276	—
Other current liabilities	1,258	1,469
Total current liabilities	3,561	4,513
Long-term debt	4,121	4,525
Accumulated deferred income taxes – net	2,726	2,915
Accumulated deferred investment tax credits	136	148
Customer advances and other deferred credits	427	609
Power-purchase contracts	213	309
Preferred stock subject to mandatory redemption	141	—
Accumulated provision for pensions and benefits	330	356
Asset retirement obligations	2,084	—
Regulatory liabilities – net	—	393
Other long-term liabilities	243	209
Total deferred credits and other liabilities	6,300	4,939
Total liabilities	13,982	13,977
Commitments and contingencies (Notes 2, 9 and 10)		
Preferred stock subject to mandatory redemption	—	147
Common stock (434,888,104 shares outstanding at each date)	2,168	2,168
Additional paid-in capital	338	340
Accumulated other comprehensive loss	(19)	(16)
Retained earnings	1,868	1,892
Total common shareholder's equity	4,355	4,384
Preferred stock not subject to mandatory redemption	129	129
Total shareholders' equity	4,484	4,513
Total liabilities and shareholders' equity	$ 18,466	$ 18,637

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

In millions Year ended December 31,	2003	2002	2001
Cash flows from operating activities:			
Income from continuing operations	$ 882	$ 1,247	$ 2,408
Adjustments to reconcile to net cash provided by operating activities:			
Depreciation, decommissioning and amortization	882	780	681
Other amortization	101	106	82
Deferred income taxes and investment tax credits	(49)	(640)	1,313
Regulatory assets – long-term – net	495	1,860	(3,135)
Gas options	75	14	(91)
Other assets	121	7	(68)
Other liabilities	(374)	132	17
Changes in working capital:			
Receivables and accrued unbilled revenue	45	338	(243)
Regulatory assets – short-term – net	697	(376)	(278)
Fuel inventory, materials and supplies	(13)	(11)	(16)
Prepayments and other current assets	(22)	41	(21)
Accrued interest and taxes	(143)	(191)	365
Accounts payable and other current liabilities	13	(2,676)	2,251
Operating cash flows from discontinued operations	(34)	—	—
Net cash provided by operating activities	2,676	631	3,265
Cash flows from financing activities:			
Long-term debt issuance costs	(11)	(32)	—
Long-term debt repaid	(1,263)	(1,200)	—
Bonds remarketed (repurchased) and funds held in trust – net	—	191	(130)
Redemption of preferred stock	(6)	(100)	—
Rate reduction notes repaid	(246)	(246)	(246)
Nuclear fuel financing – net	—	(59)	(21)
Short-term debt financing – net	(4)	(527)	676
Dividends paid	(955)	(40)	(1)
Net cash provided (used) by financing activities	(2,485)	(2,013)	278
Cash flows from investing activities:			
Additions to property and plant – net	(1,161)	(1,046)	(688)
Contributions to nuclear decommissioning trusts – net	(86)	(12)	(36)
Sales of investments in other assets	13	18	12
Investing cash flows from discontinued operations	146	—	—
Net cash used by investing activities	(1,088)	(1,040)	(712)
Net increase (decrease) in cash and equivalents	(897)	(2,422)	2,831
Cash and equivalents, beginning of year	992	3,414	583
Cash and equivalents, end of year, continuing operations	$ 95	$ 992	$ 3,414

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

Consolidated Statements of Changes in Common Shareholder's Equity — Southern California Edison Company

In millions	Common Stock	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings (Deficit)	Total Common Shareholder's Equity
Balance at December 31, 2000	$ 2,168	$ 334	$ —	$ (1,722)	$ 780
Net income				2,408	2,408
Cumulative effect of change in accounting for derivatives			398		398
Unrealized loss on and amortization of cash flow hedges			(420)		(420)
Dividends accrued on preferred stock				(22)	(22)
Capital stock expense and other		2			2
Balance at December 31, 2001	$ 2,168	$ 336	$ (22)	$ 664	$ 3,146
Net income				1,247	1,247
Minimum pension liability adjustment			(9)		(9)
Tax effect			4		4
Amortization of loss on cash flow hedges			4		4
Tax effect			7		7
Dividends accrued on preferred stock				(19)	(19)
Capital stock expense and other		4			4
Balance at December 31, 2002	$ 2,168	$ 340	$ (16)	$ 1,892	$ 4,384
Net income				932	932
Minimum pension liability adjustment			(7)		(7)
Tax effect			3		3
Unrealized loss on and amortization of cash flow hedges			2		2
Tax effect			(1)		(1)
Dividends declared on common stock				(945)	(945)
Dividends declared on preferred stock				(10)	(10)
Capital stock expense and other		(2)		(1)	(3)
Balance at December 31, 2003	$ 2,168	$ 338	$ (19)	$ 1,868	$ 4,355

Authorized common stock is 560 million shares with no par value.

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

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

Note 1. Summary of Significant Accounting Policies

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

Basis of Presentation

The consolidated financial statements include SCE and its subsidiaries. Intercompany transactions have been eliminated.

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

Financial statements prepared in compliance with accounting principles generally accepted in the United States require management to make estimates and assumptions that affect the amounts reported in the financial statements and Notes. Actual results could differ from those estimates. Certain significant estimates related to regulatory matters, financial instruments, income taxes, pension and postretirement benefits other than pensions, decommissioning and contingencies are further discussed in Notes 2, 3, 6, 7, 9 and 10 to the Consolidated Financial Statements, respectively.

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

Cash Equivalents

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

Debt and Equity Investments

Unrealized gains and losses on decommissioning trust funds increase or decrease the related regulatory asset or liability. All investments are classified as available-for-sale.

Fuel Inventory

Fuel inventory is valued under the last-in, first-out method for fuel oil, and under the first-in, first-out method for coal.

New Accounting Principles

On January 1, 2003, SCE adopted a new accounting standard, Accounting for Asset Retirement Obligations, which requires entities to record the fair value of a liability for a legal asset retirement obligation (ARO) in the period in which it is incurred. When the liability is initially recorded, the entity

capitalizes the cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is increased to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement. However, rate-regulated entities may recognize regulatory assets or liabilities as a result of timing differences between the recognition of costs as recorded in accordance with this standard and the recovery of costs through the rate-making process. Regulatory assets and liabilities may also be recorded when it is probable that the ARO will be recovered through the rate-making process.

SCE's impacts of adopting this standard were:

- SCE adjusted its nuclear decommissioning obligation to reflect the fair value of decommissioning its nuclear power facilities. SCE also recognized AROs associated with the decommissioning of other coal-fired generation assets. Fair values were determined based on site-specific studies conducted by third-party contractors.

- At December 31, 2002, SCE had accrued $2.3 billion to decommission its nuclear facilities and $12 million to decommission its share of a coal-fired generating plant, under accounting principles in effect at that time. Of these amounts, $298 million to decommission its inactive nuclear facility was recorded in other long-term liabilities, and the remaining $2.0 billion was recorded as a component of the accumulated provision for depreciation and decommissioning on the consolidated balance sheets in the 2002 Annual Report.

- As of January 1, 2003, SCE reversed the $2.3 billion it had previously recorded for decommissioning, recorded the fair value of its AROs of approximately $2.02 billion in the deferred credits and other liabilities section of the balance sheet, and increased its unamortized nuclear investment by $303 million. The cumulative effect of a change in accounting principle from unrecognized accretion expense and adjustments to depreciation, decommissioning and amortization expense recorded to date was a $354 million after-tax gain, which under accounting standards for rate-regulated enterprises was deferred as a regulatory liability, partially offset by a $235 million deferred tax asset, as of January 1, 2003. Accretion expense on the ARO ($128 million) and depreciation expense on the new asset ($15 million) resulting from the application of the new standard in 2003 reduced the regulatory liability, with no impact on earnings. SCE's ARO liability account increased from $2.02 billion to $2.08 billion in 2003, with the $128 million in accretion partially offset by $68 million in expenditures related to the decommissioning of its inactive nuclear facility. As of December 31, 2003, SCE's ARO for its nuclear facilities totaled approximately $2.07 billion and its nuclear decommissioning trust assets had a fair value of $2.5 billion. If the new standard had been in place on January 1, 2002, SCE's ARO as of that date would have been $1.98 billion. If the standard had been applied retroactively for the years ended December 31, 2002 and 2001, it would not have had any impact on SCE's results of operations.

- SCE has collected in rates amounts for the future costs of removal and decommissioning of assets, and has historically recorded these amounts in accumulated provision for depreciation. However, in accordance with recent Securities and Exchange Commission accounting guidance, the amounts accrued in accumulated provision for depreciation for decommissioning and costs of removal were reclassified to regulatory liabilities as of December 31, 2002. The cost of removal amounts collected for assets not legally required to be removed remain in regulatory liabilities as of December 31, 2003. Amounts collected through rates for cost of removal of plant assets not considered to be legal obligations ($2.02 billion at December 31, 2003 and $1.92 billion at December 31, 2002) are included in regulatory liabilities.

Effective July 1, 2003, SCE adopted a new accounting standard, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity, which required issuers to classify certain freestanding financial instruments as liabilities. These freestanding liabilities include mandatorily redeemable financial instruments, obligations to repurchase the issuer's equity shares by transferring assets and certain obligations to issue a variable number of shares. Effective July 1, 2003, SCE reclassified its preferred stock subject to mandatory redemption to the liabilities section of its consolidated balance sheet. This item was previously classified between liabilities and equity. In addition, effective July 1, 2003, dividend payments on this instrument are included in interest expense – net of amounts capitalized on SCE's consolidated statements of income. Prior period financial statements are not permitted to be restated for these changes. Therefore, upon adoption there was no cumulative impact incurred due to this accounting change. See disclosures regarding the preferred stock in Note 3.

In May 2003, the Emerging Issues Task Force (EITF) reached a consensus on Determining Whether an Arrangement Contains a Lease, which provides guidance on how to determine whether an arrangement contains a lease that is within the scope of the standard, Accounting for Leases. A lease is defined as an agreement conveying the right to use property, plant, or equipment (land and/or depreciable assets) usually for a stated period of time. The guidance issued by the EITF could affect the classification of a power sales agreement that meets specific criteria, such as a power sales agreement for substantially all of the output from a power plant to one customer. If a power sales agreement meets the guidance issued by the EITF, it would be accounted for as a lease subject to the lease accounting standard. The consensus is effective prospectively for arrangements entered into or modified after June 30, 2003. The consensus had no impact on SCE's financial statements as of December 31, 2003.

In December 2003, the Financial Accounting Standards Board issued a revision to an accounting Interpretation (originally issued in January 2003), Consolidation of Variable Interest Entities (VIEs). The primary objective of the Interpretation is to provide guidance on the identification of, and financial reporting for, so-called "variable interest entities," where control may be achieved through means other than voting rights. Under the Interpretation, the enterprise that, using a discounted cash flow method, is expected to absorb or receive the majority of a VIE's expected losses or residual returns, or both, must consolidate the VIE. This Interpretation is effective for special purpose entities, as defined by accounting principles generally accepted in the United States, as of December 31, 2003, and all other entities as of March 31, 2004.

Guidance related to implementation of this Interpretation is evolving. SCE has over 240 long-term power-purchase contracts with independent power producers that own qualifying facilities (QFs). SCE was required under federal law to sign such contracts, which typically require SCE to purchase 100% of the power produced by these facilities, and the CPUC controls the terms and pricing. Under this accounting Interpretation, SCE could be required to consolidate some or all of the entities that hold these contracts depending on 1) whether these power generators are considered to be VIEs, and 2) whether SCE is considered to be the consolidating entity. These entities are not legally obligated to provide the financial information to SCE, which would be required to determine whether SCE must consolidate these entities. SCE does not know which, if any, of these entities will provide the necessary information. SCE has no investment in, nor obligation to provide support to, these entities other than its requirement to make payment as required by the power purchase agreements. However, if SCE is required to consolidate these entities, it may be required to recognize losses to the extent of any negative equity. These losses, if any, would not affect SCE's liquidity. Edison Mission Energy, a wholly owned subsidiary of Edison International, has 49% to 50% ownership in four QF partnerships that have long-term power sales contracts with SCE. Edison Mission Energy accounts for these projects using the equity method. If long-term power-purchase contracts are deemed to be variable interests, and due to the

related-party nature of this transaction, it is likely that these four QFs could be consolidated by either Edison Mission Energy or SCE.

Nuclear

SCE's nuclear plant investments are recorded as a regulatory asset on its balance sheets. This classification does not affect the rate-making treatment for these assets. SCE had been recovering its investments in San Onofre Nuclear Generating Station (San Onofre) Units 2 and 3 and Palo Verde Nuclear Generating Station (Palo Verde) on an accelerated basis, as authorized by the CPUC. The accelerated recovery was to continue through December 2001, earning a 7.35% fixed rate of return on investment. San Onofre's operating costs, including nuclear fuel and nuclear fuel financing costs, and incremental capital expenditures, were recovered through an incentive pricing plan that allows SCE to receive about 4¢ per kilowatt-hour (kWh) through 2003. Any differences between these costs and the incentive price would flow through to shareholders. Palo Verde's accelerated plant recovery, as well as operating costs, including nuclear fuel and nuclear fuel financing costs, and incremental capital expenditures, were subject to balancing account treatment through the effective date of the 2003 general rate case.

The nuclear rate-making plans were to continue for rate-making purposes at least through the 2003 general rate case effective date for Palo Verde operating costs and through 2003 for the San Onofre incentive pricing plan. However, due to the various unresolved regulatory and legislative issues as of December 31, 2000, SCE was no longer able to conclude that the unamortized nuclear investment was probable of recovery through the rate-making process. As a result, this balance was written off as a charge to earnings at that time. As a result of the CPUC's April 4, 2002 decision that returned SCE's URG assets to cost-based ratemaking, SCE reestablished for financial reporting purposes its unamortized nuclear investment and related flow-through taxes, retroactive to August 31, 2001, based on a 10-year recovery period, effective January 1, 2001, with a corresponding credit to earnings. SCE adjusted the procurement-related obligations account (PROACT) regulatory asset balance to reflect recovery of the nuclear investment in accordance with the final URG decision.

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

Other Nonoperating Income and Deductions

Other nonoperating income and deductions are as follows:

In millions Year ended December 31,	2003	2002	2001
Property condemnation settlement	$ —	$ 38	$ —
Allowance for funds used during construction	27	19	16
Performance-based incentive award	21	—	21
Other	24	18	20
Total other nonoperating income	$ 72	$ 75	$ 57
Provisions for regulatory issues and refunds	$ —	$ (42)	$ 7
Other	41	33	31
Total other nonoperating deductions	$ 41	$ (9)	$ 38

Planned Major Maintenance

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

Purchased Power

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

In millions Year ended December 31,	2003	2002	2001
PX/ISO:			
Purchases	$ 284	$ 75	$ 775
Generation sales	—	—	324
Purchased power – PX/ISO – net	284	75	451
Purchased power – bilateral contracts	342	61	188
Purchased power – interutility/QF contracts	2,160	1,880	3,131
Total	$ 2,786	$2,016	$ 3,770

Net PX/ISO amounts for 2002 reflect only billing adjustments. These billing adjustments are recovered through the PROACT and have no impact on earnings. Net PX/ISO amounts for 2003 include ISO imbalance purchases and billing adjustments.

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

Regulatory Assets and Liabilities

In accordance with accounting principles for rate-regulated enterprises, SCE records regulatory assets, which represent probable future 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.

SCE assessed the probability of recovery of its generation-related regulatory assets in light of the CPUC's March 27, 2001 decisions. These decisions and other regulatory and legislative actions did not meet SCE's prior expectation that the CPUC would provide adequate cost recovery mechanisms. SCE was unable to conclude that its generation-related regulatory assets were probable of recovery through the rate-making process as of December 31, 2000. Therefore, in accordance with accounting rules, SCE recorded a $2.5 billion after-tax charge to earnings at that time, to write off various regulatory assets.

In accordance with an October 2001 settlement agreement between the CPUC and SCE, the CPUC passed a resolution on January 23, 2002, allowing SCE to establish the procurement-related obligations account (PROACT) regulatory asset for previously incurred energy procurement costs, retroactive to August 31, 2001. SCE fully recovered the PROACT balance during July 2003 and on August 1, 2003, transferred the PROACT overcollection to a new energy resource recovery account regulatory balancing account. The new balancing account acts as a mechanism to recover SCE's fuel costs related to its generating stations, purchased-power costs related to cogeneration and renewable contracts, existing interutility and bilateral contracts that were entered into prior to January 17, 2001, and new procurement-related costs that SCE began incurring on January 1, 2003, the date on which the CPUC transferred back to SCE the responsibility for procuring energy resources for its customers.

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

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

As part of a new accounting standard, Accounting for Asset Retirement Obligations, SCE capitalized the initial cost of the ARO into a nuclear-related ARO regulatory asset, and also recorded a nuclear-related asset retirement obligation (ARO) regulatory liability for the present value of the obligation, and an ARO regulatory liability as a result of timing differences between the recognition of costs as recorded in accordance with this standard and the recovery of the related asset retirement costs through the rate-making process. The ARO regulatory liability defers the impact on earnings of the change in accounting principle. See further discussion in "New Accounting Principles."

SCE has collected in rates amounts for the future costs of removal and decommissioning of assets, and has historically recorded these amounts in accumulated provision for depreciation. However, in accordance with recent Securities and Exchange Commission accounting guidance, the amounts accrued in accumulated provision for depreciation for decommissioning and costs of removal

were reclassified to regulatory liabilities as of December 31, 2002. Upon implementation of the new accounting standard for AROs, SCE reversed the decommissioning amounts collected for assets legally required to be removed and recorded the fair value of this ARO (included in the deferred credits and other liabilities section of the consolidated balance sheet). The cost of removal amounts collected for assets not legally required to be removed remains in regulatory liabilities as of December 31, 2003.

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

In millions December 31,	2003	2002
Current:		
PROACT – net	$ —	$ 574
Regulatory balancing accounts and other – net	(276)	(115)
	(276)	459
Long-term:		
Flow-through taxes – net	974	1,336
Rate reduction notes – transition cost deferral	949	1,215
Unamortized nuclear investment – net	601	630
Nuclear-related ARO investment – net	288	—
Unamortized coal plant investment – net	66	61
Unamortized loss on reacquired debt	222	237
Environmental remediation	71	70
ARO	(720)	—
Costs of removal	(2,020)	(4,231)
Regulatory balancing accounts and other – net	79	289
	510	(393)
Total	$ 234	$ 66

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

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

Related Party Transactions

Certain Edison Mission Energy subsidiaries have 49% to 50% ownership in partnerships (QFs) that sell electricity generated by their project facilities to SCE under long-term power purchase agreements with terms and pricing approved by the CPUC. SCE's purchases from these partnerships were $754 million in 2003, $548 million in 2002 and $983 million in 2001.

SCE holds $153 million in notes receivable from affiliates, due in June 2007. The notes were issued by Edison International in second quarter 1997, and assigned to SCE in fourth quarter 1997. A $78 million note receivable from Edison Mission Energy bears interest at LIBOR plus 0.275%; and a $75 million

note receivable from Edison Capital bears interest at a 30-day commercial paper rate (4.4% at December 31, 2003).

Restricted Cash

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

Revenue

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. Rates include amounts for current period costs, plus the recovery of certain previously incurred costs. However, in accordance with accounting standards for rate-regulated enterprises, amounts currently authorized in rates for recovery of costs to be incurred in the future are not considered as revenue until the associated costs are incurred.

Since January 17, 2001, power purchased by the CDWR or through the ISO for SCE's customers is not considered a cost to SCE, because SCE is acting as an agent for these transactions. Further, amounts billed to ($1.7 billion in 2003, $1.4 billion in 2002 and $2.0 billion in 2001) and collected from SCE's customers for these power purchases, CDWR bond-related costs (effective November 15, 2002) and direct access exit fees (effective January 1, 2003) are being remitted to the CDWR and are not recognized as revenue to SCE.

Stock-Based Employee Compensation

SCE has three stock-based employee compensation plans, which are described more fully in Note 7. SCE accounts for those plans using the intrinsic value method. Upon grant, no stock-based employee compensation cost is reflected in net income, as all options granted under those plans had an exercise price equal to the market value of the underlying common stock on the date of grant. Compensation expense recorded under the stock-compensation program was $7 million in 2003, $7 million in 2002 and $1 million in 2001. The following table illustrates the effect on net income if SCE had used the fair-value accounting method.

In millions Year ended December 31,	2003	2002	2001
Net income available for common stock, as reported	$ 922	$ 1,228	$ 2,386
Less: Additional stock-based compensation expense using the fair-value accounting method – net of tax	2	(2)	3
Pro forma net income available for common stock	**$ 920**	**$ 1,230**	**$ 2,383**

Supplemental Accumulated Other Comprehensive Loss Information

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

In millions December 31,	2003	2002
Minimum pension liability – net[1]	$ (9)	$ (5)
Unrealized losses on cash flow hedges – net	(10)	(11)
Accumulated other comprehensive loss	$ (19)	$ (16)

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

Unrealized losses on cash flow hedges relate to SCE's interest rate swap (the swap terminated on January 5, 2001 but the related debt matures in 2008). The unamortized loss of $9 million (as of December 31, 2003, net of tax) on the interest rate swap will be amortized over a period ending in 2008. Approximately $2 million, after tax, of the unamortized loss on this swap will be reclassified into earnings during 2004. Additionally, SCE recorded a $1 million unrealized loss as of December 31, 2003 on an interest rate hedge that terminated on January 7, 2004.

Supplemental Cash Flows Information

SCE supplemental cash flows information is:

In millions Year ended December 31,	2003	2002	2001
Cash payments for interest and taxes:			
Interest – net of amounts capitalized	$ 390	$ 487	$ 455
Tax payments (receipts)	585	1,110	(105)
Non-cash investing and financing activities:			
Details of debt exchange:			
Retirement of senior secured credit facility	$ (700)	—	—
Cash paid	500	—	—
Short-term credit facility utilized	$ 200	—	—
Details of long-term debt exchange offer:			
Variable rate notes redeemed	$ (966)	—	—
First and refunding mortgage bonds issued	966	—	—
Obligation to fund investment in acquisition	$ 8	—	—
Details of senior secured credit facility transaction:			
Retirement of credit facility	—	$ (1,650)	—
Senior secured credit facility replacement	—	1,600	—
Cash paid on retirement of credit facility	—	$ (50)	—

Utility Plant

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

construction. AFUDC is capitalized during plant construction and reported in current earnings in other nonoperating income. AFUDC is recovered in rates through depreciation expense over the useful life of the related asset. Depreciation of utility plant is computed on a straight-line, remaining-life basis.

Depreciation expense stated as a percent of average original cost of depreciable utility plant was 4.3% for 2003, 4.2% for 2002 and 3.6% for 2001.

AFUDC – equity was $21 million in 2003, $11 million in 2002 and $7 million in 2001. AFUDC – debt was $6 million in 2003, $8 million in 2002 and $9 million in 2001.

Replaced or retired property costs are charged to the accumulated provision for depreciation. Historically, cash payments for removal costs less salvage were charged to the accumulated provision for depreciation and decommissioning and cash collections from customers for future decommissioning were credited to accumulated provision for depreciation and decommissioning. However, as a result of recent guidance from the staff of the Securities and Exchange Commission, SCE reclassified amounts related to removal costs to regulatory liabilities in its December 31, 2003 and 2002 balance sheets. See further discussion in "New Accounting Principles" and "Regulatory Assets and Liabilities."

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

Generation plant	38 years to 81 years
Distribution plant	24 years to 53 years
Transmission plant	40 years to 60 years
Other plant	5 years to 40 years

SCE's net investment in generation-related utility plant was $867 million at December 31, 2003 and $842 million at December 31, 2002.

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

Note 2. Regulatory Matters

CDWR Power Purchases and Revenue Requirement Proceedings

In accordance with an emergency order by the Governor of California, the CDWR began making emergency power purchases for SCE's customers on January 17, 2001. In February 2001, a California law was enacted which authorized the CDWR to: (1) enter into contracts to purchase electric power and sell power at cost directly to SCE's retail customers; and (2) issue bonds to finance those electricity purchases. During the fourth quarter of 2002, the CDWR issued $11 billion in bonds to finance its electricity purchases. The CDWR's total statewide power charge and bond charge revenue requirements are allocated by the CPUC among the customers of SCE, Pacific Gas and Electric (PG&E) and San Diego Gas & Electric (SDG&E). Amounts billed to and collected from SCE's customers for electric power purchased and sold by the CDWR (approximately $1.7 billion in 2003) are remitted directly to the CDWR and are not recognized as revenue by SCE.

CPUC Litigation Settlement Agreement

During the California energy crisis, prices charged by sellers of wholesale power escalated far beyond what SCE was permitted by the CPUC to charge its customers. In November 2000, SCE filed a lawsuit

against the CPUC in federal district court seeking a ruling that SCE is entitled to full recovery of its electricity procurement costs incurred during the energy crisis in accordance with the tariffs filed with the FERC. In October 2001, SCE and the CPUC entered into a settlement of SCE's lawsuit against the CPUC. A key element of the 2001 CPUC settlement agreement was the establishment of a $3.6 billion regulatory balancing account, called the PROACT, as of August 31, 2001. The Utility Reform Network (TURN) and other parties appealed to the United States Court of Appeals for the Ninth Circuit (Ninth Circuit) seeking to overturn the stipulated judgment of the federal district court that approved the 2001 CPUC settlement agreement. On September 23, 2002, the Ninth Circuit issued its opinion affirming the federal district court on all claims, with the exception of the challenges founded upon California state law, which the Ninth Circuit referred to the California Supreme Court.

On August 21, 2003, the California Supreme Court issued its decision on the certified questions on challenges founded upon California state law, concluding that the 2001 CPUC settlement agreement did not violate California law in any of the respects raised by the Ninth Circuit. Specifically, the California Supreme Court concluded that: (1) the commissioners of the CPUC had the authority to propose the stipulated judgment under the provisions of California's restructuring statute, Assembly Bill 1890, as amended or impacted by subsequent legislation; (2) the procedures employed by the CPUC in entering the stipulated judgment did not violate California's open meeting law for public agencies; and (3) the stipulated judgment did not violate California's public utilities code by allegedly altering rates without a public hearing and issuance of findings.

On October 22, 2003, the California Supreme Court denied TURN's petition for rehearing of the decision. The matter was returned to the Ninth Circuit for final disposition, subject to any efforts by TURN to pursue further federal appeals. On December 19, 2003, the Ninth Circuit unanimously affirmed the original stipulated judgment of the federal district court, and no petition for rehearing was filed. On January 12, 2004, the Ninth Circuit issued its mandate, relinquishing jurisdiction of the case and returning jurisdiction to the federal district court. TURN and those parties whose appeals to the Ninth Circuit were consolidated with TURN's appeal currently have 90 days from December 19, 2003 in which to seek discretionary review from the United States Supreme Court. SCE continues to believe it is probable that recovery of its past procurement costs through regulatory mechanisms, including the PROACT, will not be invalidated. However, SCE cannot predict with certainty the ultimate outcome of further legal proceedings, if any.

Electric Line Maintenance Practices Proceeding

In August 2001, the CPUC issued an order instituting investigation regarding SCE's overhead and underground electric line maintenance practices. The order was based on a report issued by the CPUC's Consumer Protection and Safety Division, which alleged a pattern of noncompliance with the CPUC's general orders for the maintenance of electric lines for 1998–2000. The order also alleged that noncompliant conditions were involved in 37 accidents resulting in death, serious injury or property damage. The Consumer Protection and Safety Division identified 4,817 alleged violations of the general orders during the three-year period; and the order put SCE on notice that it could be subject to a penalty of between $500 and $20,000 for each violation or accident. In its opening brief on October 21, 2002, the Consumer Protection and Safety Division recommended that SCE be assessed a penalty of $97 million.

On June 19, 2003, a CPUC administrative law judge issued a presiding officer's decision on the Consumer Protection and Safety Division report. The decision did the following:

- Fined SCE $576,000 for 2% of the alleged violations involving death, injury or property damage, failure to identify unsafe conditions or exceeding required inspection intervals. The decision did not

find that any of the alleged violations compromised the integrity or safety of SCE's electric system or were excessive compared to other utilities.

- Ordered SCE to consult with the Consumer Protection and Safety Division and refine SCE's maintenance priority system consistent with the decision.

- Adopted an interpretation that all of SCE's nonconformances with the CPUC's general orders for the maintenance of electric lines are violations subject to potential penalty.

On July 21, 2003, SCE filed an appeal with the CPUC challenging, among other things, the decision's interpretation of nonconformance. The Consumer Protection and Safety Division also appealed, challenging the fact that the decision did not penalize SCE for 4,721 of the 4,817 alleged violations. A final decision is scheduled to be issued on March 16, 2004.

Generation Procurement Proceedings

SCE resumed power procurement responsibilities for its residual-net short position on January 1, 2003, pursuant to CPUC orders and California statutes passed in 2002. The current regulatory and statutory framework requires SCE to assume limited responsibilities for CDWR contracts allocated by the CPUC, and provide full power procurement responsibilities on the basis of annual short-term procurement plans, long-term resource plans and increased procurement of renewable resources.

Short-Term Procurement Plan

In 2003, SCE operated under a CPUC-approved short-term procurement plan, which includes contracts entered into during a transitional period beginning in August 2002 for deliveries in 2003 and the allocation of CDWR contracts. In December 2003, the CPUC adopted a 2004 procurement plan for SCE, which established a target level for spot market purchases equal to 5% of monthly need, and allowed SCE to enter into contracts of up to five years.

Long-Term Resource Plan

On April 15, 2003, SCE filed its long-term resource plan with the CPUC, which includes a 20-year forecast. SCE's long-term resource plan included both a preferred plan and an interim plan (both described below). On January 22, 2004, the CPUC issued a decision which did not adopt any long-term resource plan, but adopted a framework for resource planning. Until the CPUC approves a long-term resource plan for SCE, SCE will operate under its interim resource plan.

- Preferred Resource Plan: The preferred resource plan contains long-term commitments intended to encourage investment in new generation and transmission infrastructure, increase long-term reliability and decrease price volatility. These commitments include energy efficiency and demand-response investments, additional renewable resource contracts that will meet or exceed the requirements of legislation passed in 2002, additional utility and third-party owned generation, and new major transmission projects.

- Interim Resource Plan: The interim resource plan, by contrast, relies exclusively on new short- and medium-term contracts with no long-term resource commitments (except for new renewable contracts).

In its long-term resource plan filing, SCE maintained that implementation of its preferred resource plan requires resolution of various issues including: (1) stabilizing SCE's customer base; (2) restoring SCE's

investment-grade creditworthiness; (3) restructuring regulations regarding energy efficiency and demand-response programs; (4) removing barriers to transmission development; (5) modifying prior decisions, which impede long-term procurement; and (6) adopting a commercially realistic cost-recovery framework that will enable utilities to obtain financing and enable contracting for new generation.

Under the framework adopted in the CPUC's January 22, 2004 decision, all load-serving entities in California have an obligation to procure sufficient resources to meet their customers' needs. This resource adequacy requirement phases in over the 2005–2008 period and requires planning reserve margins of 15%–17% of peak load. The decision requires SCE to enter into forward contracts for 90% of SCE's summer peaking needs a year in advance and to file a revised long-term resource plan in 2004. The decision does not comprehensively address important issues SCE has raised about its customer base, recovery of indirect procurement costs (including debt equivalence) and other matters.

Procurement of Renewable Resources

As part of SCE's resumption of power procurement, in accordance with a California statute passed in 2002, SCE is required to increase its procurement of renewable resources by at least 1% of its annual electricity sales per year so that 20% of its annual electricity sales are procured from renewable resources by no later than December 31, 2017. In June 2003, the CPUC issued a decision adopting preliminary rules and guidance on renewable procurement-related issues, including penalties for noncompliance with renewable procurement targets. As of December 31, 2003, SCE procured approximately 18% of its annual electricity from renewable resources.

SCE has received bids for renewable resource contracts in response to a solicitation it made in August 2003, and is proceeding to enter into negotiations for contracts with some bidders based upon its preliminary bid evaluation.

CDWR Contract Allocation and Operating Order

The CDWR power-purchase contracts entered into as a result of the California energy crisis have been allocated on a contract-by-contract basis among SCE, PG&E and SDG&E, in accordance with a 2002 CPUC decision. SCE only assumes scheduling and dispatch responsibilities and acts only as a limited agent for the CDWR for contract implementation. Legal title, financial reporting and responsibility for the payment of contract-related bills remain with the CDWR. The allocation of CDWR contracts to SCE significantly reduces SCE's residual-net short and also increases the likelihood that SCE will have excess power during certain periods. SCE has incorporated the CDWR contracts allocated to it in its procurement plans. Wholesale revenue from the sale of excess power, if any, is prorated between the CDWR and SCE.

SCE's maximum annual disallowance risk exposure for contract administration, including administration of allocated CDWR contracts and least cost dispatch of CDWR contract resources, is $37 million. In addition, gas procurement, including hedging transactions, associated with the CDWR contracts is included within the cap.

Holding Company Proceeding

In April 2001, the CPUC issued an order instituting investigation that reopened the past CPUC decisions authorizing utilities to form holding companies and initiated an investigation into, among other things: (1) whether the holding companies violated CPUC requirements to give first priority to the capital needs of their respective utility subsidiaries; (2) any additional suspected violations of laws or CPUC rules and

decisions; and (3) whether additional rules, conditions, or other changes to the holding company decisions are necessary.

In January 2002, the CPUC issued an interim decision interpreting the CPUC requirement that the holding companies give first priority to the capital needs of their respective utility subsidiaries. The decision stated that, at least under certain circumstances, holding companies are required to infuse all types of capital into their respective utility subsidiaries when necessary to fulfill the utility's obligation to serve its customers. The decision did not determine whether any of the utility holding companies had violated this requirement, reserving such a determination for a later phase of the proceedings. In February 2002, SCE and Edison International filed an application before the CPUC for rehearing of the decision. In July 2002, the CPUC affirmed its earlier decision on the first priority requirement and also denied Edison International's request for a rehearing of the CPUC's determination that it had jurisdiction over Edison International in this proceeding. In August 2002, Edison International and SCE jointly filed a petition in California state court requesting a review of the CPUC's decisions with regard to first priority requirements, and Edison International filed a petition for a review of the CPUC decision asserting jurisdiction over holding companies. PG&E and SDG&E and their respective holding companies filed similar challenges, and all cases have been transferred to the First District Court of Appeals in San Francisco. On November 26, 2003, the Court of Appeals issued an order indicating it would hear the cases but not decide the merits of the petitions. Oral argument was held before the Court of Appeals on March 5, 2004, and the Court of Appeals is expected to rule within 90 days.

Mohave Generating Station and Related Proceedings

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

Due to the lack of progress in negotiations with the Tribes and other parties to resolve several coal and water supply issues, SCE's application stated that SCE would probably be unable to extend Mohave's operation beyond 2005. The uncertainty over a 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 pollution-control equipment that must be put in place in order for Mohave to continue to operate beyond 2005, pursuant to a 1999 consent decree concerning air quality.

Negotiations are continuing among the relevant parties in an effort to resolve the coal and water supply issues, but no resolution has been reached. The Mohave co-owners, the Tribes and the federal government have recently finalized a memorandum of understanding under which the Mohave co-owners will fund, subject to the terms and conditions of the memorandum of understanding, a $6 million study of a possible alternative groundwater source for the slurry water. The study is expected to begin in early 2004. SCE and other parties submitted further testimony and made various other filings in 2003 in SCE's application proceeding. On February 9, 2004, the CPUC held a prehearing conference to discuss whether additional testimony and hearings are needed to determine the future of the plant. The CPUC has not issued any ruling as result of the prehearing conference, but has indicated that further testimony can be expected in early to mid-2004. The outcome of the coal and water negotiations and SCE's application are not expected to impact Mohave's operation through 2005, but could have a major impact on SCE's long-term resource plan.

For additional matters related to Mohave, see "Navajo Nation Litigation" in Note 10.

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

Wholesale Electricity and Natural Gas Markets

In 2000, the FERC initiated an investigation into the justness and reasonableness of rates charged by sellers of electricity in the PX/ISO markets. On March 26, 2003, the FERC staff issued a report concluding that there had been pervasive gaming and market manipulation of both the electric and natural gas markets in California and on the West Coast during 2000–2001 and describing many of the techniques and effects of that market manipulation. 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. Under the 2001 CPUC settlement agreement, mentioned in "CPUC Litigation Settlement Agreement," 90% of any refunds actually realized by SCE will be refunded to customers, except for the El Paso Natural Gas Company settlement agreement discussed below.

El Paso Natural Gas Company entered into a settlement agreement with parties to a class action lawsuit (including SCE, PG&E and the State of California) settling claims stated in proceedings at the FERC and in San Diego County Superior Court that El Paso Natural Gas Company had manipulated interstate capacity and engaged in other anticompetitive behavior in the natural gas markets in order to unlawfully raise gas prices at the California border in 2000–2001. The San Diego County Superior Court approved the settlement on December 5, 2003. Notice of appeal of that judgment was filed by a party to the action on February 6, 2004. Accordingly, until the appeal is resolved, the judgment is not final and no refunds will be paid. Pursuant to a CPUC decision, SCE will refund to customers any amounts received under the terms of the El Paso Natural Gas Company settlement (net of legal and consulting costs) through its energy resource recovery account mechanism. In addition, amounts El Paso Natural Gas Company refunds to the CDWR will result in equivalent reductions in the CDWR's revenue requirement allocated to SCE.

On February 24, 2004, SCE and PG&E entered into a settlement agreement with The Williams Cos. and Williams Power Company, providing for approximately $140 million in refunds against some of Williams' power charges in 2000–2001. The allocation of refunds under the settlement agreement has not been determined. The settlement is subject to the approval of the FERC, the CPUC and the PG&E bankruptcy court.

Note 3. Derivative Instruments and Hedging Activities

SCE's risk management policy allows the use of derivative financial instruments to manage financial exposure on its investments, fluctuations in interest rates and energy prices, but prohibits the use of these instruments for speculative or trading purposes.

On January 1, 2001, SCE adopted a new accounting standard for derivative instruments and hedging activities. SCE also adopted subsequent interpretations of this standard. The standard requires derivative instruments to be recognized on the balance sheet at fair value unless they meet the definition

of a normal purchase or sale. The normal purchases and sales exception requires, among other things, physical delivery in quantities expected to be used or sold over a reasonable period in the normal course of business. Gains or losses from changes in the fair value of a recognized asset or liability or a firm commitment are reflected in earnings for the ineffective portion of the hedge. For a hedge of the cash flows of a forecasted transaction, the effective portion of the gain or loss is initially recorded as a separate component of shareholder's equity under the caption "accumulated other comprehensive income," and subsequently reclassified into earnings when the forecasted transaction affects earnings. The ineffective portion of the hedge is reflected in earnings immediately.

SCE recorded its interest rate swap agreement (terminated January 5, 2001) and its block forward power-purchase contracts at fair value effective January 1, 2001. The unamortized loss of $9 million (as of December 31, 2003, net of tax) on the interest rate swap will be amortized over a period ending in 2008, when the related debt matures.

In December 2003, SCE entered into an interest rate lock to hedge its exposure to changes in interest rates for $825 million of anticipated issuances of first mortgage bonds. SCE recorded a $1 million liability as of December 31, 2003, representing the fair value of the interest rate lock. The lock expired on January 7, 2004, the pricing date of $975 million of new mortgage bonds, resulting in a payment of $6 million to the counterparties due to a decline in treasury rates. This loss will be treated as a debt discount and amortized over the life of the mortgage bonds.

SCE has bilateral forward power contracts, which are considered normal purchases under accounting rules. SCE is exposed to credit loss in the event of nonperformance by the counterparties to its bilateral forward contracts, but does not expect the counterparties to fail to meet their obligations. The counterparties are required to post collateral depending on the creditworthiness of each counterparty.

In October and November 2001, SCE purchased $209 million of call options that mitigated its exposure to increases in natural gas prices during 2002 and 2003. This amount was recovered through a balancing account mechanism. Amounts paid to QFs for energy are based on natural gas prices. Any fair value changes for gas call options are offset through a regulatory balancing account; therefore, fair value changes do not affect earnings. In fourth quarter 2003, SCE purchased $4 million of call options to hedge some gas price exposure for 2004.

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

Fair values of financial instruments are:

In millions December 31,	2003	2002
Financial assets:		
Decommissioning trusts	$ 2,530	$ 2,210
Commodity price derivatives:		
Natural gas	3	77
Financial liabilities:		
Interest rate hedges	1	—
DOE decommissioning and decontamination fees	18	22
QF power contracts	32	70
Long-term debt	4,446	4,543
Long-term debt due within one year	377	1,722
Preferred stock subject to mandatory redemption	139	129
Preferred stock to be redeemed within one year	9	8

Financial assets' fair values are based on quoted market prices for decommissioning trusts and financial models for commodity price derivatives.

Financial liabilities' fair values are based on: discounted future cash flows for United States Department of Energy (DOE) decommissioning and decontamination fees; financial models for QF power contracts; and brokers' quotes for interest rate hedges, long-term debt and preferred stock.

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

Note 4. Liabilities

Almost all SCE properties are subject to a trust indenture lien. SCE has pledged first and refunding mortgage bonds as security for borrowed funds obtained from pollution-control bonds issued by government agencies. SCE used these proceeds to finance construction of pollution-control facilities. Bondholders have limited discretion in redeeming certain pollution-control bonds, and SCE has arrangements with securities dealers to remarket or purchase them if necessary. As a result of investors' concerns regarding SCE's liquidity difficulties and overall financial condition, SCE had to repurchase $550 million of pollution-control bonds in December 2000 and early 2001 that could not be remarketed in accordance with their terms. On March 1, 2002, SCE remarketed $196 million of the pollution-control bonds that SCE had repurchased in late 2000.

Debt premium, discount and issuance expenses are amortized over the life of each issue. Under CPUC rate-making procedures, debt reacquisition expenses are amortized over the remaining life of the reacquired debt or, if refinanced, the life of the new debt. California law prohibits SCE from incurring or guaranteeing debt for its nonutility affiliates.

In December 1997, $2.5 billion of rate reduction notes were issued on behalf of SCE by SCE Funding LLC, a special purpose entity. These notes were issued to finance the 10% rate reduction mandated by state law. The proceeds of the rate reduction notes were used by SCE Funding LLC to purchase from SCE an enforceable right known as transition property. Transition property is a current property right created by the restructuring legislation and a financing order of the CPUC and consists generally of the right to be paid a specified amount from nonbypassable rates charged to residential and small commercial

customers. The rate reduction notes are being repaid over 10 years through these nonbypassable residential and small commercial customer rates, which constitute the transition property purchased by SCE Funding LLC. The notes are collateralized by the transition property and are not collateralized by, or payable from, assets of SCE or Edison International. SCE used the proceeds from the sale of the transition property to retire debt and equity securities. Although, as required by accounting principles generally accepted in the United States, SCE Funding LLC is consolidated with SCE and the rate reduction notes are shown as long-term debt in the consolidated financial statements, SCE Funding LLC is legally separate from SCE. The assets of SCE Funding LLC are not available to creditors of SCE or Edison International and the transition property is legally not an asset of SCE or Edison International.

Long-term debt is:

In millions December 31,	2003	2002
First and refunding mortgage bonds:		
2004 – 2026 (5.875% to 8.00% and variable)	$1,816	$2,275
Rate reduction notes:		
2004 – 2007 (6.38% to 6.42%)	985	1,232
Pollution-control bonds:		
2005 – 2040 (5.125% to 7.2% and variable)	1,216	1,216
Bonds repurchased	(354)	(354)
Debentures and notes:		
2006 – 2053 (5.06% to 7.625% and variable)	758	1,750
Subordinated debentures:		
2044 (8.375%)	100	100
Long-term debt due within one year	(371)	(1,671)
Unamortized debt discount – net	(29)	(23)
Total	$4,121	$4,525

Note: rates and terms as of December 31, 2003

Long-term debt maturities and sinking-fund requirements for the next five years are: 2004 – $371 million; 2005 – $442 million; 2006 – $446 million; 2007 – $1.2 billion; and 2008 – zero.

At December 31, 2003, SCE had $200 million in outstanding short-term debt as part of a credit line with a limit of $700 million. The weighted-average rate for this short-term debt was 2.83%.

At December 31, 2002, SCE had no short-term debt, no available short-term credit lines and had fully drawn a long-term credit line of $300 million.

In January 2004, SCE issued $975 million of first and refunding mortgage bonds. The issuance included $300 million of 5% bonds due in 2014, $525 million of 6% bonds due in 2034 and $150 million of floating rate bonds due in 2006. The proceeds were used to redeem $300 million of 7.25% first and refunding mortgage bonds due March 2026, $225 million of 7.125% first and refunding mortgage bonds due July 2025, $200 million of 6.9% first and refunding mortgage bonds due October 2018, and $100 million of junior subordinated deferrable interest debentures due June 2044. In March 2004, SCE remarketed approximately $550 million of pollution-control bonds with varying maturity dates ranging from 2008 to 2040.

In compliance with a new accounting standard, effective July 1, 2003, SCE reclassified its preferred stock subject to mandatory redemption to the liabilities section of its consolidated balance sheet. This item was previously classified between liabilities and equity.

SCE has 12 million authorized shares of preferred stock subject to mandatory redemption. Mandatorily redeemable preferred stock is subject to sinking-fund provisions. When preferred shares are redeemed, the premiums paid, if any, are charged to expense.

Preferred stock redemption requirements for the next five years are: 2004 – $9 million; 2005 – $9 million; 2006 – $9 million; 2007 – $69 million; and 2008 – $54 million.

Cumulative preferred stock subject to mandatory redemption is:

Dollars in millions, except per-share amounts	December 31,		2003	2002
	December 31, 2003			
	Shares Outstanding	Redemption Price		
$100 par value:				
6.05% Series	693,800	$ 100.00	$ 69	$ 75
7.23	807,000	100.00	81	81
Preferred stock to be redeemed within one year			(9)	(9)
Total			**$141**	**$147**

In 2001, SCE did not redeem any preferred stock. In 2002, SCE redeemed 1,000,000 shares of 6.45% Series preferred stock. In 2003, SCE redeemed 56,200 shares of 6.05% Series preferred stock. SCE did not issue any preferred stock in the last three years.

The 7.23% Series preferred stock has mandatory sinking funds, requiring SCE to redeem at least 50,000 shares per year from 2002 through 2006, and 750,000 shares in 2007. However, SCE is allowed to credit previously repurchased shares against the mandatory sinking fund provisions. Since SCE had previously repurchased 193,000 shares of this series, no shares were redeemed in 2002 or 2003. At December 31, 2003, SCE had 93,000 of previously repurchased, but not retired, shares available to credit against the mandatory sinking fund provisions.

Note 5. Preferred Stock Not Subject to Mandatory Redemption

SCE's authorized shares are: $25 cumulative preferred – 24 million and preference – 50 million. All cumulative preferred stock is redeemable. When preferred shares are redeemed, the premiums paid, if any, are charged to common equity.

Cumulative preferred stock not subject to mandatory redemption is:

Dollars in millions, except per-share amounts	December 31, 2003 Shares Outstanding	December 31, 2003 Redemption Price	2003	2002
$25 par value:				
4.08% Series	1,000,000	$ 25.50	$ 25	$ 25
4.24	1,200,000	25.80	30	30
4.32	1,653,429	28.75	41	41
4.78	1,296,769	25.80	33	33
Total			$129	$129

Note 6. Income Taxes

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

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

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

In millions December 31,	2003	2002
Deferred tax assets:		
Accrued charges	$ 334	$ 416
Investment tax credits	68	73
Property-related	243	178
Regulatory balancing accounts	144	5,365
Unrealized gains or losses	365	274
Decommissioning	166	—
Other	199	212
Total	$1,519	$ 6,518
Deferred tax liabilities:		
Property-related	$2,762	$ 2,847
Capitalized software costs	160	204
Regulatory balancing accounts	360	5,606
Unrealized gains and losses	262	171
Decommissioning	30	—
Other	163	306
Total	$3,737	$ 9,134
Accumulated deferred income taxes – net	$2,218	$ 2,616
Classification of accumulated deferred income taxes:		
Included in deferred credits	$2,726	$ 2,915
Included in current assets	508	299

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

In millions Year ended December 31,	2003	2002	2001
Current:			
Federal	$ 408	$ 990	$ 240
State	174	273	29
	582	1,263	269
Deferred:			
Federal	(134)	(504)	1,052
State	(60)	(117)	337
	(194)	(621)	1,389
Total	$ 388	$ 642	$1,658

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

Year ended December 31,	2003	2002	2001
Federal statutory rate	35.0%	35.0%	35.0%
Favorable resolution of audit	(2.8)	(1.9)	—
Resolution of FERC rate case	(5.9)	—	—
Property-related and other	(1.8)	(4.5)	—
State tax – net of federal deduction	6.0	5.4	5.8
Effective tax rate	30.5%	34.0%	40.8%

The composite federal and state statutory income tax rate was 40.551% for all years presented. The lower effective tax rate of 34% realized in 2002 was primarily due to reestablishing a tax-related regulatory asset due to implementation of the utility-retained generation decision and recording the benefit of favorable settlement of Internal Revenue Service (IRS) audits.

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

Note 7. Employee Compensation and Benefit Plans

Employee Savings Plan

SCE has a 401(k) defined contribution savings plan designed to supplement employees' retirement income. The plan received employer contributions of $33 million in 2003, $30 million in 2002 and $29 million in 2001.

Pension Plan

Defined benefit pension plans (the non-executive plan has a cash balance feature) cover employees meeting minimum service requirements. SCE recognizes pension expense for its non-executive plan as calculated by the actuarial method used for ratemaking.

At December 31, 2003 and December 31, 2002, the accumulated benefit obligations of the executive pension plans exceeded the related plan assets at the measurement dates. In accordance with accounting

standards, SCE's balance sheets include an additional minimum liability, with corresponding charges to intangible assets and shareholder's equity (through a charge to accumulated other comprehensive income). The charge to accumulated other comprehensive income would be restored through shareholder's equity in future periods to the extent the fair value of the plan assets exceed the accumulated benefit obligation.

The expected contributions (all by the employer) are approximately $33 million for the year ended December 31, 2004. This amount is subject to change based on, among other things, the limits established for federal tax deductibility.

SCE uses a December 31 measurement date for all of its plans.

Information on plan assets and benefit obligations is shown below:

In millions Year ended December 31,	2003	2002
Change in projected benefit obligation		
Projected benefit obligation at beginning of year	$ 2,550	$ 2,371
Service cost	79	69
Interest cost	162	158
Actuarial loss	148	90
Benefits paid	(130)	(138)
Projected benefit obligation at end of year	$ 2,809	$ 2,550
Accumulated benefit obligation at end of year	$ 2,424	$ 2,177
Change in plan assets		
Fair value of plan assets at beginning of year	$ 2,281	$ 2,723
Actual return on plan assets	594	(311)
Employer contributions	34	7
Benefits paid	(130)	(138)
Fair value of plan assets at end of year	$ 2,779	$ 2,281
Funded status	$ (30)	$ (269)
Unrecognized net loss	111	394
Unrecognized transition obligation	6	11
Unrecognized prior service cost	84	98
Recorded asset	$ 171	$ 234
Additional detail of amounts recognized in balance sheets:		
Intangible asset	$ 3	$ 3
Accumulated other comprehensive income	(16)	(9)
Pension plans with an accumulated benefit obligation in excess of plan assets:		
Projected benefit obligation	$ 78	$ 55
Accumulated benefit obligation	60	41
Fair value of plan assets	—	—
Weighted-average assumptions at end of year:		
Discount rate	6.0%	6.5%
Rate of compensation increase	5.0%	5.0%

Expense components are:

In millions Year ended December 31,	2003	2002	2001
Service cost	$ 79	$ 69	$ 69
Interest cost	162	158	157
Expected return on plan assets	(187)	(224)	(251)
Special termination benefits	3	—	13
Net amortization and deferral	34	21	(7)
Expense under accounting standards	91	24	(19)
Regulatory adjustment – deferred	(44)	(18)	39
Total expense recognized	$ 47	$ 6	$ 20
Change in accumulated other comprehensive income	$ (7)	$ (9)	—
Weighted-average assumptions:			
Discount rate	6.5%	7.0%	7.25%
Rate of compensation increase	5.0%	5.0%	5.0%
Expected return on plan assets	8.5%	8.5%	8.5%

Asset allocations are:

	Target for 2004	December 31, 2003	2002
United States equity	45%	46%	45%
Non-United States equity	25	26	25
Private equity	4	3	3
Fixed income	26	25	27

Postretirement Benefits Other Than Pensions

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.

On December 8, 2003, President Bush signed the Medicare Prescription Drug, Improvement and Modernization Act of 2003. The Act authorized a federal subsidy to be provided to plan sponsors for certain prescription drug benefits under Medicare. SCE has elected to defer accounting for the effects of the Act until the earlier of the issuance of guidance by the Financial Accounting Standards Board on how to account for the Act, or the remeasurement of plan assets and obligations subsequent to January 31, 2004. Accordingly, any measures of the accumulated postretirement benefit obligation or net periodic postretirement benefit expense in the financial statements or this Note do not reflect the effects of the Act on SCE's plan. Specific authoritative guidance on the accounting for the federal subsidy is pending and that guidance, when issued, could require SCE to restate previously reported information.

The expected contributions (all by the employer) to the postretirement benefits other than pensions trust are $100 million for the year ended December 31, 2004. This amount is subject to change based on, among other things, the Act referenced above and the impact of any benefit plan amendments.

SCE uses a December 31 measurement date.

Information on plan assets and benefit obligations is shown below:

In millions Year ended December 31,	2003	2002
Change in benefit obligation		
Benefit obligation at beginning of year	$ 2,103	$ 1,925
Service cost	42	42
Interest cost	122	133
Amendments	(622)	—
Actuarial loss	581	82
Benefits paid	(89)	(79)
Benefit obligation at end of year	$ 2,137	$ 2,103
Change in plan assets		
Fair value of plan assets at beginning of year	$ 1,072	$ 1,139
Actual return on plan assets	291	(148)
Employer contributions	115	160
Benefits paid	(89)	(79)
Fair value of plan assets at end of year	$ 1,389	$ 1,072
Funded status	$ (748)	$ (1,031)
Unrecognized net loss	1,027	702
Unrecognized transition obligation	(342)	268
Recorded asset (liability)	$ (63)	$ (61)
Assumed health care cost trend rates:		
Rate assumed for following year	12.0%	9.75%
Ultimate rate	5.0%	5.0%
Year ultimate rate reached	2010	2008
Weighted-average assumptions at end of year:		
Discount rate	6.25%	6.75%

Expense components are:

In millions Year ended December 31,	2003	2002	2001
Service cost	$ 42	$ 42	$ 44
Interest cost	122	133	129
Expected return on plan assets	(89)	(93)	(98)
Special termination benefits	1	—	2
Net amortization and deferral	41	37	27
Total expense	$ 117	$ 119	$ 104
Assumed health care cost trend rates:			
Current year	9.75%	10.5%	11.0%
Ultimate rate	5.0%	5.0%	5.0%
Year ultimate rate reached	2008	2008	2008
Weighted-average assumptions:			
Discount rate	6.4%	7.25%	7.5%
Expected return on plan assets	8.2%	8.2%	8.2%

Increasing the health care cost trend rate by one percentage point would increase the accumulated obligation as of December 31, 2003 by $305 million and annual aggregate service and interest costs by $27 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated obligation as of December 31, 2003 by $248 million and annual aggregate service and interest costs by $22 million.

Asset allocations are:

	Target for 2004	December 31, 2003	2002
United States equity	64%	64%	64%
Non-United States equity	16	13	13
Fixed income	20	23	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. SCE employs multiple investment management firms. Investment managers within each asset class cover a range of investment styles and approaches. Risk is controlled through diversification among multiple asset classes, managers, styles and securities. Plan, asset class and individual manager performance is measured against targets. SCE also monitors the stability of its investments managers' organizations.

Allowable investment types include:

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

Non-United States Equity: 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 non-publicly traded entities.

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

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

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

The overall expected long term rate of return on assets assumption is based on the target asset allocation for plan assets, capital markets return forecasts for asset classes employed, and active management excess return expectations. A portion of postretirement benefits other than pensions 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 non-government 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.

Active Management Excess Return Expectations

For asset classes that are actively managed, an excess return premium is added to the capital market return forecasts discussed above.

Stock-Based Employee Compensation

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

Under the 1992, 1998 and 2000 plans, options on 8.6 million shares of Edison International common stock are currently outstanding to officers and senior managers of SCE.

Each option may be exercised to purchase one share of Edison International common stock and is exercisable at a price equivalent to the fair market value of the underlying stock at the date of grant. Options generally expire 10 years after date of grant and vest over a period of up to five years.

Edison International stock options awarded prior to 2000 include a dividend equivalent feature. Dividend equivalents on stock options issued after 1993 and prior to 2000 are accrued to the extent dividends are declared on Edison International common stock and are subject to reduction unless certain performance criteria are met. Only a portion of the 1999 Edison International stock option awards include a dividend equivalent feature. The 2003 options include a dividend equivalent feature for the first five years of the option term. Dividend equivalents accumulate without interest.

Options issued after 1997 generally have a four-year vesting period. The special options granted in 2000 vest over five years, in 25% increments beginning in May 2002. Earlier options had a three-year vesting period with one-third of the total award vesting annually. If an option holder retires, dies, is terminated by the company, or is terminated while permanently and totally disabled (qualifying event) during the vesting period, the unvested options will vest on a pro rata basis.

Unvested options of any person who has served in the past on the SCE management committee (which was dissolved in 1993) will vest and be exercisable upon a qualifying event. If a qualifying event occurs, the vested options may continue to be exercised within their original terms by the recipient or beneficiary except that in the case of termination by the company where the option holder is not eligible for retirement, vested options are forfeited unless exercised within one year of termination date. If an option holder is terminated other than by a qualifying event, options which had vested as of the prior anniversary date of the grant are forfeited unless exercised within 180 days of the date of termination. All unvested options are forfeited on the date of termination.

The fair value for each option granted, reflecting the basis for the pro forma disclosures in Note 1, was determined on the date of grant using the Black-Scholes option-pricing model. The following assumptions were used in determining fair value through the model:

December 31,	2003	2002	2001
Expected life	10 years	7 years – 10 years	7 years – 10 years
Risk-free interest rate	3.8% – 4.5%	4.7% – 6.1%	4.7% – 6.1%
Expected dividend yield	1.8%	1.8%	3.3%
Expected volatility	44% – 53%	18% – 54%	17% – 52%

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

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

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

			Weighted-Average		
	Share Options	Exercise Price	Exercise Price	Fair Value At Grant	Remaining Life
Outstanding, Dec. 31, 2000	10,770,629	$14.56–$29.25	$22.56		8 years
Granted	324,934	$ 9.15–$15.92	$12.64	$4.51	
Expired	(8,400)	$18.75–$19.35	$19.10		
Forfeited	(5,830,582)	$15.41–$28.94	$20.99		
Exercised	—	—	—		
Outstanding, Dec. 31, 2001	5,256,581	$ 9.15–$29.25	$23.70		6 years
Granted	1,769,017	$ 8.90–$18.73	$18.54	$7.86	
Expired	(138,899)	$14.07–$28.94	$24.88		
Forfeited	(73,651)	$14.07–$28.13	$21.04		
Exercised	(2,250)	$14.07–$15.94	$15.26		
Outstanding, Dec. 31, 2002	6,810,798	$ 8.90–$29.25	$22.37		6 years
Granted	2,076,070	$11.88–$19.80	$12.41	$7.34	
Expired	(115,612)	$14.06–$29.25	$22.98		
Forfeited	(59,473)	$12.29–$18.73	$15.34		
Exercised	(156,697)	$11.35–$20.19	$18.71		
Outstanding, Dec. 31, 2003	8,555,086	$ 8.90–$28.94	$20.06		6 years

The number of options exercisable and their weighted-average exercise prices at December 31, 2003, 2002 and 2001 were 4,845,967 at $24.06, 4,160,675 at $24.23 and 3,699,622 at $23.92, respectively.

For the years after 1999, a portion of the executive long-term incentives was awarded in the form of performance shares. Performance shares were awarded in January 2001, January 2002 and January 2003. The performance shares vest December 31, 2003, December 31, 2004 and December 31, 2005, respectively, and are paid out half in shares of Edison International common stock and half in cash. The number of shares that will be paid out from the 2002 and 2003 performance share awards will depend on the performance of Edison International common stock relative to the stock performance of a specified group of peer companies. The 2001 performance share values are accrued ratably over a three-year performance period. The 2002 and 2003 performance shares will be valued based on Edison International's stock performance relative to the stock performance of other such entities.

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

In October 2001, a stock option retention exchange offer was extended, offering holders of Edison International stock options granted in 2000 the opportunity to exchange those options for a lesser number of deferred stock units. The exchange ratio was based on the Black-Scholes value of the options and the stock price at the time the offer was extended. The exchange took place in November 2001; the options that participants elected to exchange were cancelled, and deferred stock units were issued. Approximately three options were cancelled for each deferred stock unit issued. Twenty-five percent of the deferred stock units will vest and be paid in Edison International common stock per year over four years; the first and second vesting dates were in November 2002 and November 2003, respectively. The following assumptions were used in determining fair value through the Black-Scholes option-pricing model: expected life – 8 to 9 years; risk-free interest rate – 5.1%; expected volatility – 52%.

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

Note 8. Jointly Owned Utility Projects

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

The investment in each project as of December 31, 2003 is:

In millions	Investment in Facility	Accumulated Depreciation and Amortization	Ownership Interest
Transmission systems:			
Eldorado	$ 45	$ 11	60%
Pacific Intertie	257	80	50
Generating stations:			
Four Corners Units 4 and 5 (coal)	488	384	48
Mohave (coal)[1]	347	257	56
Palo Verde (nuclear)[2]	1,657	1,460	16
San Onofre (nuclear)[2]	4,297	3,923	75
Total	$ 7,091	$ 6,115	

[1] A portion is included in regulatory assets on the balance sheet. See Note 1.
[2] Included in regulatory assets on the balance sheet.

Note 9. Commitments

Leases

SCE has operating leases, primarily for vehicles, with varying terms, provisions and expiration dates. Operating lease expense was $15 million in 2003, $16 million in 2002 and $19 million in 2001.

Estimated remaining commitments for noncancelable leases at December 31, 2003 are:

Year ended December 31,	In millions
2004	$ 13
2005	10
2006	7
2007	6
2008	4
Thereafter	8
Total	$ 48

Nuclear Decommissioning

Effective January 1, 2003, SCE adopted a new accounting standard, Accounting for Asset Retirement Obligations, which requires entities to record the fair value of a liability for a legal ARO in the period in which it is incurred. At that time, SCE adjusted its nuclear decommissioning obligation, increased its unamortized nuclear investment for a new ARO asset, and recorded a regulatory liability to defer the impact on earnings of the change in accounting principle (see further details in "New Accounting Principles" in Note 1). The fair value of decommissioning SCE's nuclear power facilities is $2.1 billion as of December 31, 2003, based on site-specific studies performed in 2001 for San Onofre and Palo Verde. Changes in the estimated costs, timing of decommissioning, or the assumptions underlying these estimates could cause material revisions to the estimated total cost to decommission in the near term. SCE estimates that it will spend approximately $11.4 billion through 2049 to decommission its nuclear

facilities. This estimate is based on SCE's current-dollar decommissioning cost methodology used for rate-making purposes, escalated at rates ranging from 0.9% to 10.0% (depending on the cost element) annually. These costs are expected to be funded from independent decommissioning trusts, which effective October 2003 receive contributions of approximately $32 million per year. SCE estimates annual after-tax earnings on the decommissioning funds of 3.7% to 6.5%. If the assumed return on trust assets is not earned, it is probable that additional funds needed for decommissioning will be recoverable through rates.

Decommissioning of San Onofre Unit 1 (shut down in 1992 per CPUC agreement) started in 1999 and will continue through 2008. All of SCE's San Onofre Unit 1 decommissioning costs will be paid from its nuclear decommissioning trust funds. The estimated remaining cost to decommission San Onofre Unit 1 is recorded as an ARO liability ($177 million at December 31, 2003). Total expenditures for the decommissioning of San Onofre Unit 1 were $317 million through December 31, 2003.

SCE plans to decommission its nuclear generating facilities by a prompt removal method authorized by the Nuclear Regulatory Commission. Decommissioning is expected to begin after the plants' operating licenses expire. The operating licenses expire in 2022 for San Onofre Units 2 and 3, and in 2024, 2026 and 2027 for the Palo Verde units. Decommissioning costs, which are recovered through nonbypassable customer rates over the term of each nuclear facility's operating license, are recorded as a component of depreciation expense, with a corresponding credit to the ARO regulatory liability. The earnings impact of amortization of the ARO asset included within the unamortized nuclear investment and accretion of the ARO liability, both created under this new standard, are deferred as increases to the ARO regulatory liability account, with no impact on earnings.

SCE has collected in rates amounts for the future costs of removal of its nuclear assets, and has historically recorded these amounts in accumulated provision for depreciation and decommissioning. However, in accordance with recent Securities and Exchange Commission accounting guidance, the amounts accrued in accumulated provision for depreciation and decommissioning for nuclear decommissioning and costs of removal were reclassified to regulatory liabilities as of December 31, 2002. Upon implementation of the new accounting standard for AROs, SCE reversed the decommissioning amounts collected for assets legally required to be removed and recorded the fair value of this ARO (included in the deferred credits and other liabilities section of the consolidated balance sheet). The cost of removal amounts collected for assets not legally required to be removed remain in regulatory liabilities as of December 31, 2003.

Decommissioning expense under the rate-making method was $118 million in 2003, $73 million in 2002 and $96 million in 2001. The ARO for decommissioning SCE's active nuclear facilities was $1.9 billion at December 31, 2003 and $1.8 billion at December 31, 2002.

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

Trust investments (at fair value) include:

In millions	Maturity Dates	December 31,	2003	2002
Municipal bonds	2004 – 2041		$ 702	$ 486
Stock	–		1,324	1,085
United States government issues	2004 – 2033		363	264
Corporate bonds	2004 – 2038		91	270
Short-term	2004		50	105
Total			$ 2,530	$2,210

Note: Maturity dates as of December 31, 2003

Trust fund earnings (based on specific identification) increase the trust fund balance and the ARO regulatory liability. Net earnings (loss) were $93 million in 2003, $(25) million in 2002 and $13 million in 2001. Proceeds from sales of securities (which are reinvested) were $2.2 billion in 2003, $3.8 billion in 2002 and $3.9 billion in 2001. Gross unrealized holding gains were $677 million and $443 million at December 31, 2003 and 2002, respectively. There were no unrealized holding losses for the years presented. Approximately 91% of the cumulative trust fund contributions were tax-deductible.

Other Commitments

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

SCE has power-purchase contracts with certain QFs (cogenerators and small power producers) and other utilities. These contracts provide for capacity payments if a facility meets certain performance obligations and energy payments based on actual power supplied to SCE. There are no requirements to make debt-service payments. In an effort to replace higher-cost contract payments with lower-cost replacement power, SCE has entered into purchased-power settlements to end its contract obligations with certain QFs. The settlements are reported as power purchase contracts on the balance sheets.

SCE has unconditional purchase obligations for part of a power plant's generating output, as well as firm transmission service from another utility. Minimum payments are based, in part, on the debt-service requirements of the provider, whether or not the plant or transmission line is operable. SCE's minimum commitment under both contracts is approximately $139 million through 2017. The purchased-power contract is expected to provide approximately 5% of current or estimated future operating capacity, and is reported as power purchase contracts (approximately $28 million). The transmission service contract requires a minimum payment of approximately $6 million a year.

Certain commitments for the years 2004 through 2008 are estimated below:

In millions	2004	2005	2006	2007	2008
Fuel supply contract payments	$ 182	$ 126	$ 58	$ 66	$ 51
Purchased-power capacity payments	682	663	637	637	444

Note 10. Contingencies

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

Employee Compensation and Benefit Plans

On July 31, 2003, a federal district court held that the formula used in a cash balance pension plan created by International Business Machine Corporation (IBM) in 1999 violated the age discrimination provisions of the Employee Retirement Income Security Act of 1974. In its decision, the federal district court set forth a standard for cash balance pension plans. This decision, however, conflicts with the decisions from two other federal district courts and with the proposed regulations for cash balance pension plans issued by IRS in December 2002. On February 12, 2004, the same federal district court ruled that IBM must make back payments to workers covered under this plan. IBM has indicated that it will appeal both decisions to the United States Court of Appeals for the Seventh Circuit. The formula for SCE's cash balance pension plan does not meet the standard set forth in the federal district court's July 31, 2003 decision. SCE cannot predict with certainty the effect of the two IBM decisions on SCE's cash balance pension plan.

Environmental Remediation

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

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

SCE's recorded estimated minimum liability to remediate its 26 identified sites is $92 million. In third quarter 2003, SCE sold certain oil storage and pipeline facilities. This sale caused a reduction in SCE's recorded estimated minimum environmental liability. The ultimate costs to clean up SCE's identified sites may vary from its recorded liability due to numerous uncertainties inherent in the estimation process, such as: the extent and nature of contamination; the scarcity of reliable data for identified sites; the varying costs of alternative cleanup methods; developments resulting from investigatory studies; the possibility of identifying additional sites; and the time periods over which site remediation is expected to occur. SCE believes that, due to these uncertainties, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $238 million. The upper limit of this range of costs was estimated using assumptions least favorable to SCE among a range of reasonably possible outcomes.

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 $71 million for its estimated minimum environmental-cleanup costs expected to be recovered through customer rates.

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

SCE expects to clean up its identified sites over a period of up to 30 years. Remediation costs in each of the next several years are expected to range from $13 million to $25 million. Recorded costs for 2003 were $14 million.

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

Federal Income Taxes

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

Investigation Regarding Performance Incentives Rewards

SCE is eligible under its CPUC-approved performance-based ratemaking (PBR) mechanism to earn rewards or penalties based on its performance in comparison to CPUC-approved standards of reliability, customer satisfaction, and employee safety. SCE received two letters over the last year from 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 to SCE under the PBR provisions for customer satisfaction. SCE is conducting an internal investigation and has determined that some wrongdoing by a number of the service planning employees has occurred. SCE has informed the CPUC of its findings to date, and will continue to inform the CPUC of developments as the investigation progresses. SCE anticipates that, after the investigation is completed, there may be CPUC proceedings to determine whether any portion of past and potential rewards for customer satisfaction should be refunded or disallowed. It also is possible that penalties could be imposed. SCE recorded aggregate customer satisfaction rewards of $28 million for the years 1998, 1999, and 2000. Potential customer satisfaction rewards aggregating $10 million for 2001 and 2002 are pending before the CPUC and have not been recognized in income by SCE. SCE also had anticipated that it could be eligible for customer satisfaction rewards of about $10 million for 2003. SCE has not yet been able to determine whether or to

what extent employee misconduct has compromised the surveys that are the basis for a portion of the awards. Accordingly, SCE cannot predict with certainty the outcome of this matter. SCE plans to complete its investigation as quickly as possible and cooperate fully with the CPUC in taking appropriate remedial action.

Navajo Nation Litigation

In June 1999, the Navajo Nation filed a complaint in the United States District Court for the District of Columbia (D.C. District Court) against Peabody Holding Company (Peabody) and certain of its affiliates, Salt River Project Agricultural Improvement and Power District, and SCE arising out of the coal supply agreement for Mohave. The complaint asserts claims for, among other things, violations of the federal Racketeer Influenced and Corrupt Organizations statute, interference with fiduciary duties and contractual relations, fraudulent misrepresentation by nondisclosure, and various contract-related claims. The complaint claims that the defendants' actions prevented the Navajo Nation from obtaining the full value in royalty rates for the coal. The complaint seeks damages of not less than $600 million, trebling of that amount, and punitive damages of not less than $1 billion, as well as a declaration that Peabody's lease and contract rights to mine coal on Navajo Nation lands should be terminated. SCE joined Peabody's motion to strike the Navajo Nation's complaint. In addition, SCE and other defendants filed motions to dismiss.

Some of the issues included in this case were addressed by the United States Supreme Court in a separate legal proceeding filed by the Navajo Nation in the Court of Federal Claims against the United States Department of Interior. In that action, the Navajo Nation claimed that the Government breached its fiduciary duty concerning negotiations relating to the coal lease involved in the Navajo Nation's lawsuit against SCE and Peabody. On March 4, 2003, the Supreme Court concluded, by majority decision, that there was no breach of a fiduciary duty and that the Navajo Nation did not have a right to relief against the Government. Based on the Supreme Court's analysis, on April 28, 2003, SCE filed a motion to dismiss or, in the alternative, for summary judgment in the D.C. District Court action. The motion remains pending.

The Federal Circuit Court of Appeals, acting on a suggestion on remand filed by the Navajo Nation, held in a October 24, 2003 decision that the Supreme Court's March 24, 2003 decision was focused on three specific statutes or regulations and therefore did not address the question of whether a network of other statutes, treaties and regulations imposed judicially enforceable fiduciary duties on the United States during the time period in question. The Government and the Navajo Nation both filed petitions for rehearing of the October 24, 2003 Court of Appeals decision. Both petitions were denied on March 9, 2004.

SCE cannot predict with certainty the outcome of the 1999 Navajo Nation's complaint against SCE, the impact of the Supreme Court's decision in the Navajo Nation's suit against the Government on this complaint, or the impact of the complaint on the operation of Mohave beyond 2005.

Nuclear Insurance

Federal law limits public liability claims from a nuclear incident to $10.9 billion. SCE and other owners of the San Onofre and Palo Verde Nuclear Generating Stations 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 Nuclear Regulatory Commission exempted San Onofre Unit 1 from this secondary level, effective June 1994. The maximum deferred premium for each nuclear incident is $101 million per reactor, but not more than

$10 million per reactor may be charged in any one year for each incident. Based on its ownership interests, SCE could be required to pay a maximum of $199 million per nuclear incident. However, it would have to pay no more than $20 million per incident in any one year. Such amounts include a 5% surcharge if additional funds are needed to satisfy public liability claims and are subject to adjustment for inflation. If the public liability limit above is insufficient, federal regulations may impose further revenue-raising measures to pay claims, including a possible additional assessment on all licensed reactor operators. The United States Congress has extended the expiration date of the applicable law until December 31, 2004.

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

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 has the obligation to begin acceptance of spent nuclear fuel not later than January 31, 1998. However, the DOE did not meet its obligation. It is not certain when the DOE will begin accepting spent nuclear fuel from San Onofre or other nuclear power plants. Extended delays by the DOE have led to the construction of costly alternatives, including 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 Federal Court of Claims seeking damages for DOE's failure to meet its obligation to begin accepting spent nuclear fuel from San Onofre.

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 1, 2 and 3 spent fuel pools and the San Onofre independent spent fuel storage installation. Movement of Unit 1 spent fuel from the Unit 3 spent fuel pool to the independent spent fuel storage installation was completed in late 2003. Movement of Unit 1 spent fuel from the Unit 1 spent fuel pool to the independent spent fuel storage installation is scheduled to be completed by late 2004 and from the Unit 2 spent fuel pool to the independent spent fuel storage installation by late 2005. With these moves, there will be sufficient space in the Unit 2 and 3 spent fuel pools to meet plant requirements through mid-2007 and mid-2008, respectively. In order to maintain a full core off-load capability, SCE is planning to begin moving Unit 2 and 3 spent fuel into the independent spent fuel storage installation by early 2006.

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

Note 11. Mountainview Acquisition

On July 17, 2003, SCE signed an option agreement with Sequoia Generating LLC, a subsidiary of InterGen, to acquire Mountainview Power Company LLC, the owner of a new power plant currently

being developed in Redlands, California. This acquisition requires regulatory approval from both the CPUC and the FERC. On December 18, 2003, the CPUC approved SCE's application proposing a power-purchase agreement between SCE and Mountainview Power Company LLC. On February 25, 2004, the FERC granted conditional approval of the power-purchase agreement. On February 28, 2004, SCE exercised its option to purchase Mountainview. The purchase is expected to close in March 2004. SCE will recommence full construction of the project once the purchase closes.

Note 12. Discontinued Operations

On July 10, 2003, the CPUC approved SCE's sale of certain oil storage and pipeline facilities to Pacific Terminals LLC for $158 million. In third quarter 2003, SCE recorded a $44 million after-tax gain to shareholders. In accordance with an accounting standard related to the impairment and disposal of long-lived assets, this oil storage and pipeline facilities unit's results have been accounted for as a discontinued operation in the 2003 financial statements. Due to immateriality, the results of this unit for prior years have not been restated and are reflected as part of continuing operations.

For 2003, revenue from discontinued operations was $20 million and pre-tax income was $82 million. As of December 31, 2002, assets of discontinued operations were $62 million.

Quarterly Financial Data (Unaudited)

	2003					2002				
In millions	Total	Fourth	Third	Second	First	Total	Fourth	Third	Second	First
Operating revenue	$8,854	$1,859	$2,794	$2,386	$1,815	$8,706	$1,952	$2,714	$2,133	$1,907
Operating income	1,596	301	613	418	264	2,127	264	452	1,107	304
Net income	932	223	375	229	105	1,247	157	238	700	152
Net income available for common stock	922	222	374	225	101	1,228	153	234	695	146
Common dividends declared	945	945	—	—	—	—	—	—	—	—

Selected Financial and Operating Data: 1999 – 2003				Southern California Edison Company	
Dollars in millions	2003	2002	2001	2000	1999
Income statement data:					
Operating revenue	$ 8,854	$ 8,706	$ 8,126	$ 7,870	$ 7,548
Operating expenses	7,258	6,579	3,509	10,529	6,242
Purchased-power expenses	2,786	2,016	3,770	4,687	3,190
Income tax (benefit)	388	642	1,658	(1,022)	438
Provisions for regulatory adjustment clauses – net	1,138	1,502	(3,028)	2,301	(763)
Interest expense – net of amounts capitalized	457	584	785	572	483
Net income (loss)	932	1,247	2,408	(2,028)	509
Net income (loss) available for common stock	922	1,228	2,386	(2,050)	484
Ratio of earnings to fixed charges	3.81	4.21	6.15	*	2.94
*less than 1.00					
Balance sheet data:					
Assets	$ 18,466	$ 18,637	$ 22,453	$ 15,966	$ 17,657
Gross utility plant	16,973	16,232	15,982	15,653	14,851
Accumulated provision for depreciation and decommissioning	4,386	4,057	7,969	7,834	7,520
Short-term debt	200	—	2,127	1,451	796
Common shareholder's equity	4,355	4,384	3,146	780	3,133
Preferred stock:					
Not subject to mandatory redemption	129	129	129	129	129
Subject to mandatory redemption	141	147	151	256	256
Long-term debt	4,121	4,525	4,739	5,631	5,137
Capital structure:					
Common shareholder's equity	49.8%	47.7%	38.5%	11.5%	36.2%
Preferred stock:					
Not subject to mandatory redemption	1.5%	1.4%	1.6%	1.9%	1.5%
Subject to mandatory redemption	1.6%	1.6%	1.9%	3.8%	2.9%
Long-term debt	47.1%	49.3%	58.0%	82.8%	59.4%
Operating data:					
Peak demand in megawatts (MW)	20,136	18,821	17,890	19,757	19,122
Generation capacity at peak (MW)	9,861	9,767	9,802	9,886	10,431
Kilowatt-hour deliveries (in millions)	93,826	79,693	78,524	84,430	78,602
Total energy requirement (kWh) (in millions)	77,159	71,663	83,495	82,503	78,752
Energy mix:					
Thermal	37.9%	40.2%	32.5%	36.0%	35.5%
Hydro	5.2%	5.0%	3.6%	5.4%	5.6%
Purchased power and other sources	56.9%	54.8%	63.9%	58.6%	58.9%
Customers (in millions)	4.60	4.53	4.47	4.42	4.36
Full-time employees	12,698	12,113	11,663	12,593	13,040

BOARD OF DIRECTORS

John E. Bryson [3]
Chairman of the Board,
President and Chief Executive Officer,
Edison International;
Chairman of the Board,
Southern California Edison Company;
Chairman of the Board, Edison Capital
(a financial investment nonutility
subsidiary of Edison International)
A director from 1990 – 1999;
2003 to present

Alan J. Fohrer [3]
Chief Executive Officer,
Southern California Edison Company
A director since 2002

Bradford M. Freeman [1,4,5]
Founding Partner,
Freeman Spogli & Co.
(private investment company)
Los Angeles, California
A director since 2002

Bruce Karatz [2,5]
Chairman and Chief Executive Officer,
KB Home (homebuilding)
Los Angeles, California
A director since 2002

Luis G. Nogales [2,4]
Managing Partner,
Nogales Investors, LLC
(private equity investment company)
Los Angeles, California
A director since 1993

Ronald L. Olson [3,4]
Senior Partner,
Munger, Tolles and Olson (law firm)
Los Angeles, California
A director since 1995

James M. Rosser [2,3,5]
President,
California State University, Los Angeles
Los Angeles, California
A director since 1985

Richard T. Schlosberg, III [1,5]
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]
Robert H. Smith Investments
and Consulting
(banking and financial-related
consulting services)
Pasadena, California
A director since 1987

Thomas C. Sutton [1,2,3]
Chairman of the Board and
Chief Executive Officer,
Pacific Life Insurance Company
Newport Beach, California
A director since 1995

Daniel M. Tellep [1,4 *]
Retired Chairman of the Board,
Lockheed Martin Corporation
(aerospace industry)
Saratoga, California
A director since 1992

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

* Retiring May 20, 2004

MANAGEMENT TEAM

John E. Bryson
Chairman of the Board

Alan J. Fohrer
Chief Executive Officer

Robert G. Foster
President

Harold B. Ray
Executive Vice President, Generation

Pamela A. Bass
Senior Vice President, Customer Service

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

Stephen E. Pickett
Senior Vice President and General Counsel

Richard M. Rosenblum
Senior Vice President, Transmission and Distribution

W. James Scilacci
Senior Vice President and Chief Financial Officer

Mahvash Yazdi
Senior Vice President, Business Integration, and Chief Information Officer

Emiko Banfield
Vice President, Shared Services

Robert C. Boada
Vice President and Treasurer

William L. Bryan
Vice President, Major Customer Division

Jodi M. Collins
Vice President, Information Technology

Diane L. Featherstone
Vice President and General Auditor

Bruce C. Foster
Vice President, Regulatory Operations

Polly L. Gault
Vice President, Public Affairs, Washington, D.C.

A. Larry Grant
Vice President, Power Delivery

Frederick J. Grigsby, Jr.
Vice President, Human Resources and Labor Relations

Harry B. Hutchison
Vice President, Customer Service Operations

James A. Kelly
Vice President, Engineering and Technical Services

Russ W. Krieger
Vice President, Power Production

Thomas M. Noonan
Vice President and Controller

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

Barbara J. Parsky
Vice President, Corporate Communications

Pedro J. Pizarro
Vice President, Power Procurement, and General Manager, Edison Carrier Solutions

Frank J. Quevedo
Vice President, Equal Opportunity

Anthony L. Smith
Vice President, Tax

Joseph J. Wambold
Vice President, Nuclear Generation

Beverly P. Ryder
Corporate Secretary

ANNUAL MEETING

The annual meeting of shareholders will be held on Thursday, May 20, 2004, at 10:00 a.m., Pacific Daylight Time, at the Hyatt Regency Long Beach, 200 South Pine Avenue, Long Beach, California 90802.

CORPORATE GOVERNANCE PRACTICES

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

STOCK LISTING AND TRADING INFORMATION

Preferred Stock

SCE's 4.08%, 4.24%, 4.32% and 4.78% Series of cumulative preferred stock are listed on the American and Pacific stock exchanges under the ticker symbol SCE. Previous day's closing prices, when traded, are listed in the daily newspapers in the American Stock Exchange composite table. The 6.05% and 7.23% Series of the $100 cumulative preferred stock are not listed and are traded over-the-counter.

TRANSFER AGENT AND REGISTRAR

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

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

Inquiries may also be directed to:

Mail

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

Fax

(651) 450-4033

Email

stocktransfer@wellsfargo.com

Web Address

www.edisoninvestor.com

Online account information:

www.shareowneronline.com

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SOUTHERN CALIFORNIA
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626.302.1212
www.edison.com

ASD055

CDRD 2664070 Unit 2 FWCS Performance During High Rate Blowdowns Adverse Evaluation

Problem Description
During steam generator high rate blowdowns (in Unit 2) on SG #1 an anomaly in level behavior was observed. Hot leg blowdown was performed successfully and cold leg blowdown initiated per procedure 40OP-9SG03. Contrary to normal response, SG #1 level continued to decrease beyond the normal level of ~35% NR to ~28% NR. The control room staff then placed blowdown to OFF terminating the event. After level stabilization, 40OP-9SG03 was continued and SG#2 was completed satisfactorily with no anomalies. See Attached Media for ERFDADS plots of both SG#1 and SG#2 responses. High rate blowdown had been successfully performed on 01/02/2004 with no anomalies.

Evaluation/Cause

In Unit 2, as a result of the RSG Project and Power Uprate, the high rate blowdown results in a feedwater flow change that can now exceed the full range span of the feedwater flow instrumentation thereby inhibiting normal FWCS response while this condition exists. This condition is marginal on the other blowdowns for exceeding the full range span of the feedwater flow instruments. It is speculated that subtle differences in the SG1 cold leg blowdown valve setting or piping contributed to this extra flow and created this situation.

Control Systems are designed for known situations. If a control system is taken outside of its expected performance area, the resulting performance can not be guaranteed. Exceeding 10Mlbm/hr was not expected for this evolution. The poor performance experienced was not related to a hardware or maintenance issue.

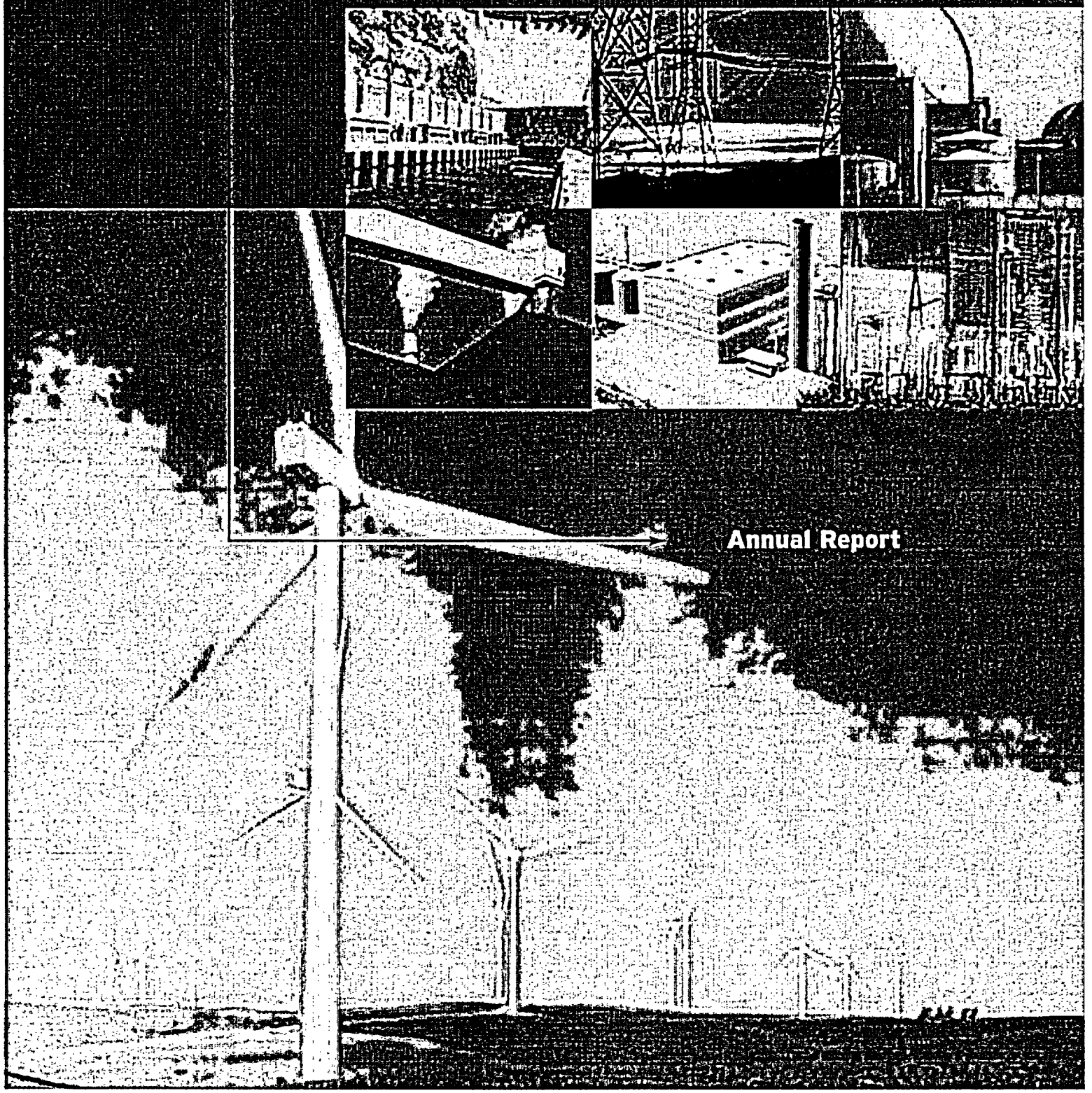
The operator's action to terminate the blowdown as level was decreasing below 30% was a procedural requirement (40OP-9SG03) and this action mitigated the event. Upon the termination of the blowdown, the system functioned normally to maintain SG level.

Transportability
This situation occurred with the Replacement SG Project and Power Uprate in Unit 2 that resulted in a new higher normal feedwater flow rate. The corrective action will be planned for implemented during the Units 1 and 3 RSG/PUR Project to avoid this situation and back-fit into Unit 2 at the first opportunity following the development of the corrective actions.

Action Plan
CRAI 2691137 developed to advance DCR 2666204 To Correct the FWCS Flow Problem and possibly re-span the feedwater flow/steam flow loops to accommodate this increased flow.

Additional guidance on this potential situation has been given to Operations and incorporated into the Prejob Briefing for the evolution.

SCPPA 2002-2003



Annual Report

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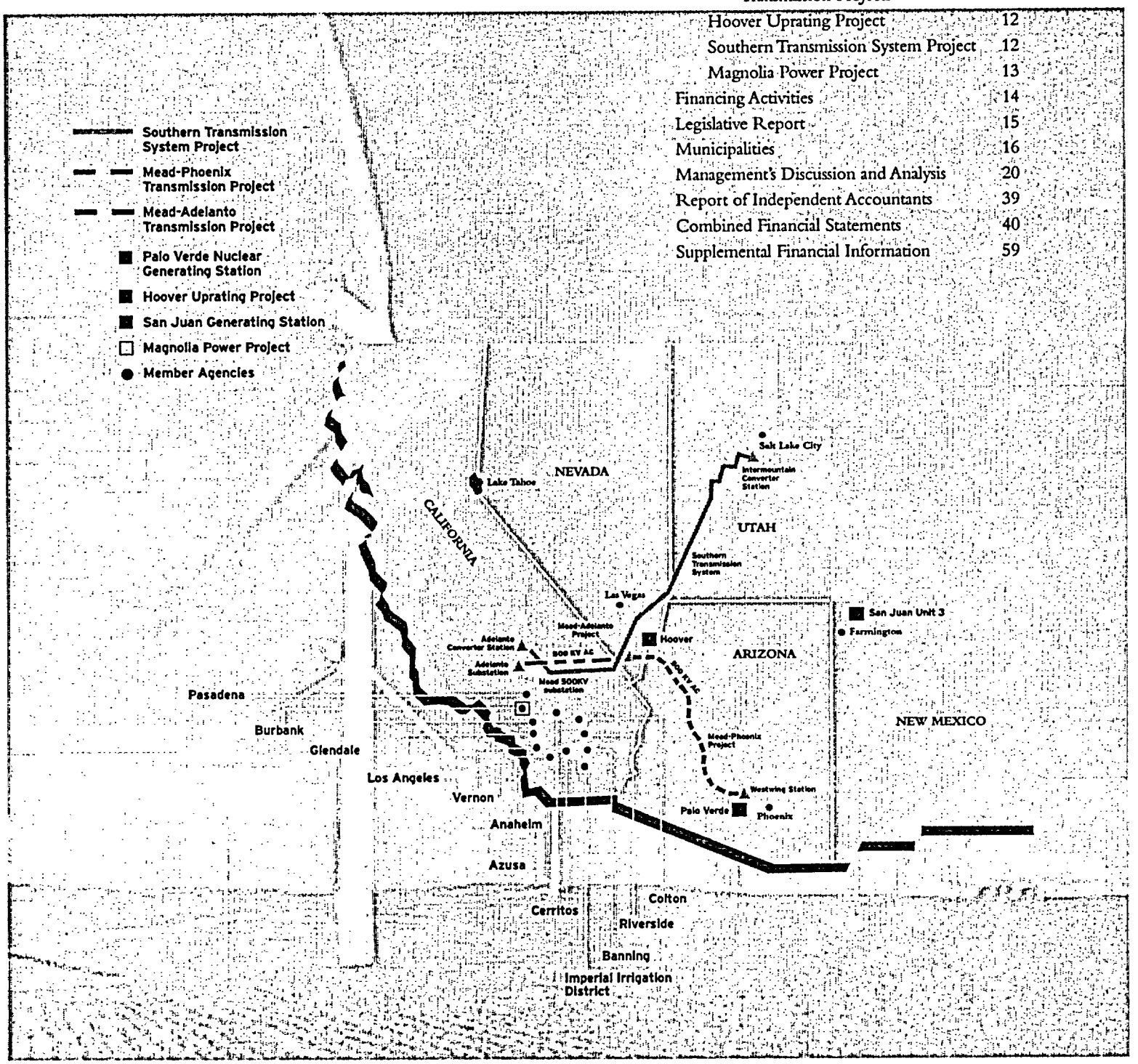


Mission

SCPPA will provide coordination, facilitation, implementation, and communication on issues and projects of mutual interest to the members as determined by the Board of Directors.

Vision

SCPPA will provide cost-effective joint action services that supplement member programs and activities to assure continued member success.

What is SCPPA?

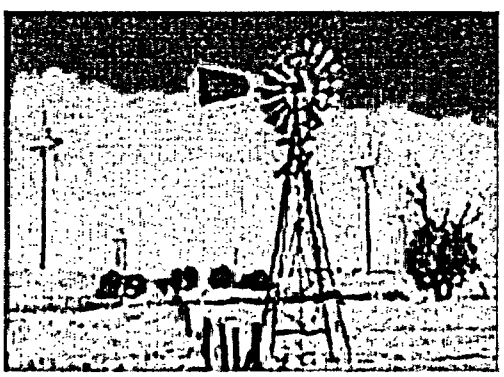
The Southern California Public Power Authority (SCPPA) is a joint powers authority consisting of the original ten municipal utilities and one irrigation district, plus one new SCPPA member utility who joined last year. SCPPA members currently deliver electricity to approximately 2 million customers over an area of 7,000 square miles, with a total population of 4.8 million.

The members are the municipal utilities of the cities of Anaheim, Azusa, Banning, Burbank, Colton, Glendale, Los Angeles, Pasadena, Riverside, and Vernon, the Imperial Irrigation District, and the municipal utility of Cerritos.

SCPPA was formed in 1980 to finance the acquisition of generation and transmission resources for its members. Currently, SCPPA has three generation projects and three transmission projects in operation, generating and bringing power from Arizona, New Mexico, Utah, and Nevada. A fourth generation project is in the construction phase.

The projects were financed through the issuance of tax-exempt bonds, backed by the combined credit of the SCPPA members participating in each project. As of June 30, 2003, SCPPA had issued $9.7 billion in bonds, notes, and refunding bonds, of which $3.0 billion was outstanding.

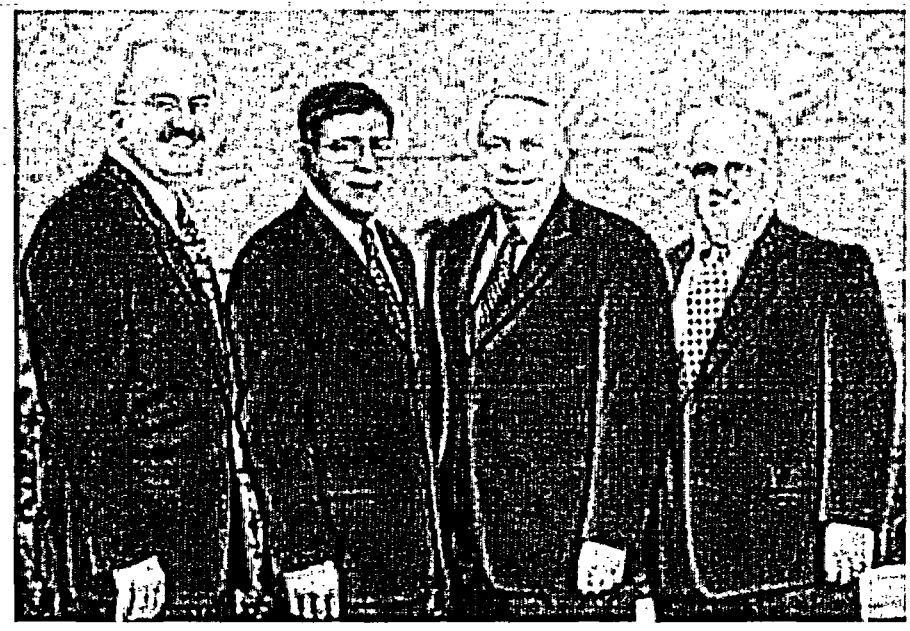
SCPPA's role has evolved over the years to include legislative advocacy at the state and national levels, and various cooperative efforts to reduce member costs and improve efficiency.



Alan R. Watts
(1935-2003)

We dedicate this year's annual report to Alan R. Watts. Alan was one of the original organizers of SCPPA, and became Special Counsel in October 1982. He served as Special and Corporate Counsel on a continuous basis for the past 21 years. His dedicated service and tireless efforts over those many years contributed greatly to SCPPA's success. We will miss him.

SCPPA Officers



Ronald E. Davis, President; Ronald O. Vazquez, Secretary; Bill D. Carnahan, Executive Director; Thomas K. Clarke, Vice President.

"SCPPA has taken advantage of low interest rates and continues to restructure its generation and transmission debt, which reduces costs to our Members and ultimately our customers."

President's Letter

As the President of the Southern California Public Power Authority (SCPPA), I am proud to be a part of the many accomplishments and the exciting opportunities for the Southern California public power utilities. I am pleased that the Authority and its individual Members are building new generation in California under the strictest environmental regulations in the nation. At the same time, we continue to work cooperatively to restore a healthy regulatory environment. We are prepared for the future with a recently developed Strategic Plan and one of the strongest financial ratings in the utility industry. Through collaboration, along with sound financial investments and a focus on the communities we serve, SCPPA is delivering reliability and competitive and stable rates every day to the 4.8 million people served by our Members.

In order to meet the growing needs of their customers, the cities of Anaheim, Burbank, Colton, Glendale, Pasadena, and Cerritos (the newest SCPPA member) joined together to begin the planning and construction of the Magnolia Power Project (Magnolia). This SCPPA-owned project held its official groundbreaking on June 10, 2003 and Magnolia is scheduled to begin producing power in 2005. When completed, Magnolia will be a combined cycled natural gas-fired generating plant with a peaking capacity of 310 megawatts and will be built on an existing site in Burbank, California. Magnolia will continue to meet the reliability needs of the project participants and will be one of the most efficient power plants thereby saving precious resources by replacing older and less-efficient power plants. By working together, these six communities will benefit by receiving locally produced and reliable energy, at competitive and stable rates.

SCPPA's executive team has spent a great deal of time developing and implementing a dynamic Strategic Plan that provides SCPPA with a focused strategic direction. In addition, SCPPA has taken advantage of low interest rates and continues to restructure its generation and transmission debt, which reduces costs to our Members and ultimately our customers. Last year, over $50 million in gross debt savings were realized to SCPPA Members. With a clear direction charted for the future and the financial strength to accomplish our goals, the opportunities abound for SCPPA's public power utilities.

Whether it is impacting energy legislation in Sacramento or on Capitol Hill or working together to meet our commitments to conservation and renewable energy resources or managing the construction of a major generating power plant, working together through SCPPA has provided our Members with proven value in financing, construction, and operation and maintenance of generation and transmissions projects. Through a combination of critical resourceful strategic planning and new load center generation, SCPPA is meeting today's and tomorrow's energy needs of our Members' customers and the communities they serve. As we look to the future, I am confident that SCPPA is poised and ready to respond to the new challenges in our industry.

Ronald E. Davis
President

"SCPPA is a leader in creating new ideas and developing new programs that continue to bring value to our Members and the communities they serve."

Executive Director's Letter

SCPPA's role continues to evolve as we find new ways, as a Joint Action Agency, to bring value to our Members so they are positioned to meet the challenges in our industry. The twelve Members of SCPPA are each independent and locally owned highly successful utilities. They provide reliable energy at competitive and stable rates with sensitivity to the communities and the environment in which they serve. Working together through SCPPA, these agencies have leveraged their talents, resources, and financial strength to collectively bring more value to their communities. I am very proud to be included in their legacy of success.

SCPPA was created in 1980 and continues in its traditional roles of providing financing for our Members' generation and transmission projects, managing various projects, and finding ways to reduce capital costs through debt refinancing. Over the last few years, SCPPA has been expanding its role in order to meet the challenges facing our industry.

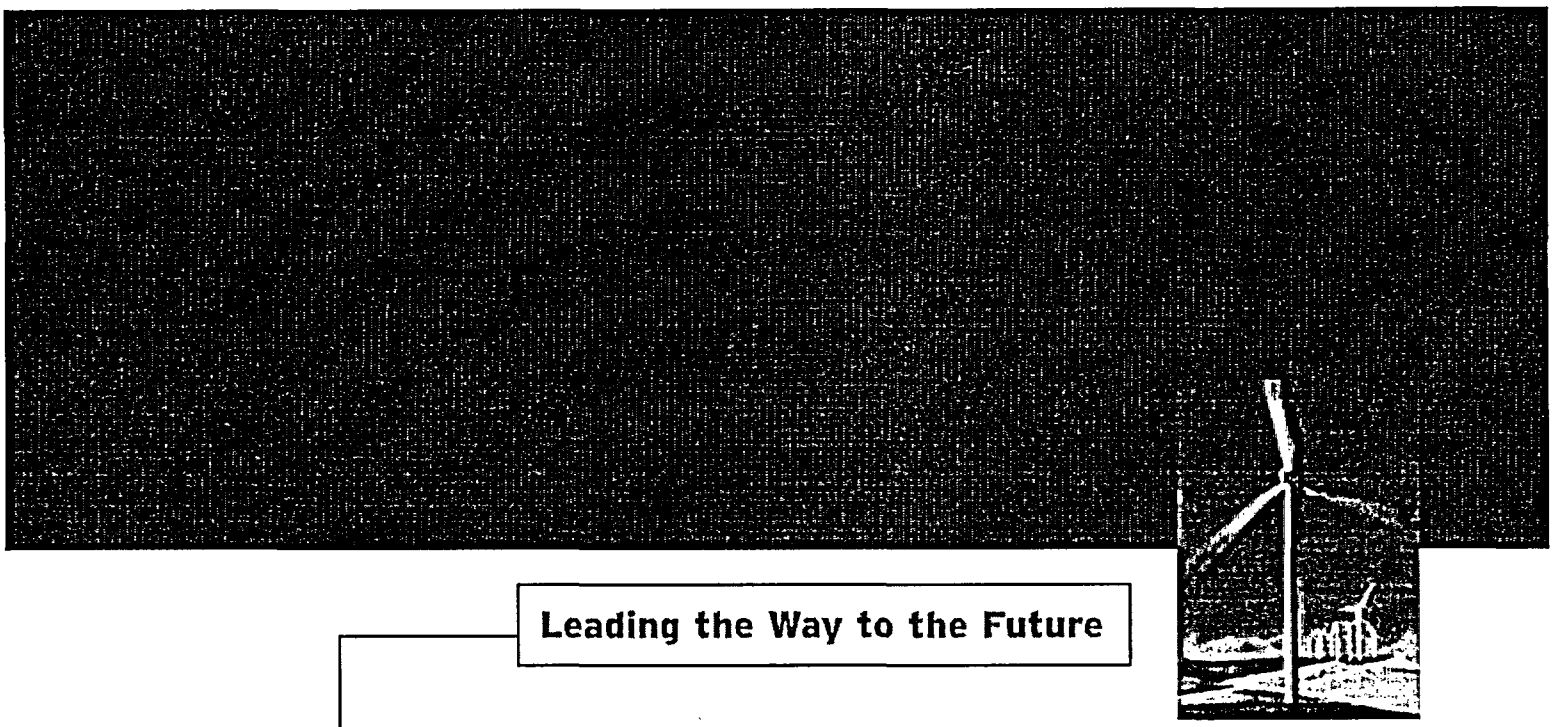
- We have increased our involvement in legislative and regulatory activities, taking a proactive approach to advocacy of public power issues in Sacramento and Washington, D.C.
- As owner of the Magnolia Power Project (Magnolia) in Burbank, California, we continue to monitor the construction and development of the new generating facility, which is scheduled for completion and operation in May 2005. Magnolia was financed on schedule and within the financing goals established by SCPPA and the six project participants, the cities of Anaheim, Burbank, Colton, Glendale, Pasadena, and Cerritos (the newest SCPPA Member). Magnolia will use the latest technology, requires less fuel, and is more efficient with significantly less pollution than the older power plants it replaces. Magnolia will also meet the strictest environmental standards and regulations in the nation.
- We have developed new committees for Customer Service and Transmission & Distribution Engineering & Operations. These new committees are working with the Members to produce benchmarking studies of best practices.
- SCPPA has developed a comprehensive and dynamic Strategic Plan that forms a common vision for our Members.

To maintain and solidify our financial strength, we continue to take advantage of low interest rates and in 2003 we restructured debt, which resulted in over $30 million in gross debt service savings for our Members.

Today, providing financing for new projects and seeking ways to reduce financing costs for existing projects remain SCPPA's primary goals. However, with the experience and benefits of working together through SCPPA, the Members have realized the value of collective leadership and are applying it in new and exciting directions. By working collaboratively in the areas of legislative activity, Public Benefits program development, resource planning and renewable resources acquisition, customer service implementation, training programs, and Transmission & Distribution Engineering & Operations, our Members are responding to the challenges and opportunities in our industry.

SCPPA, in partnership with its Members, is a leader in creating new ideas and developing new programs that continue to bring value to our Members and the communities they serve. Together, we are accomplishing more.

Bill D. Carnahan
Executive Director



Leading the Way to the Future

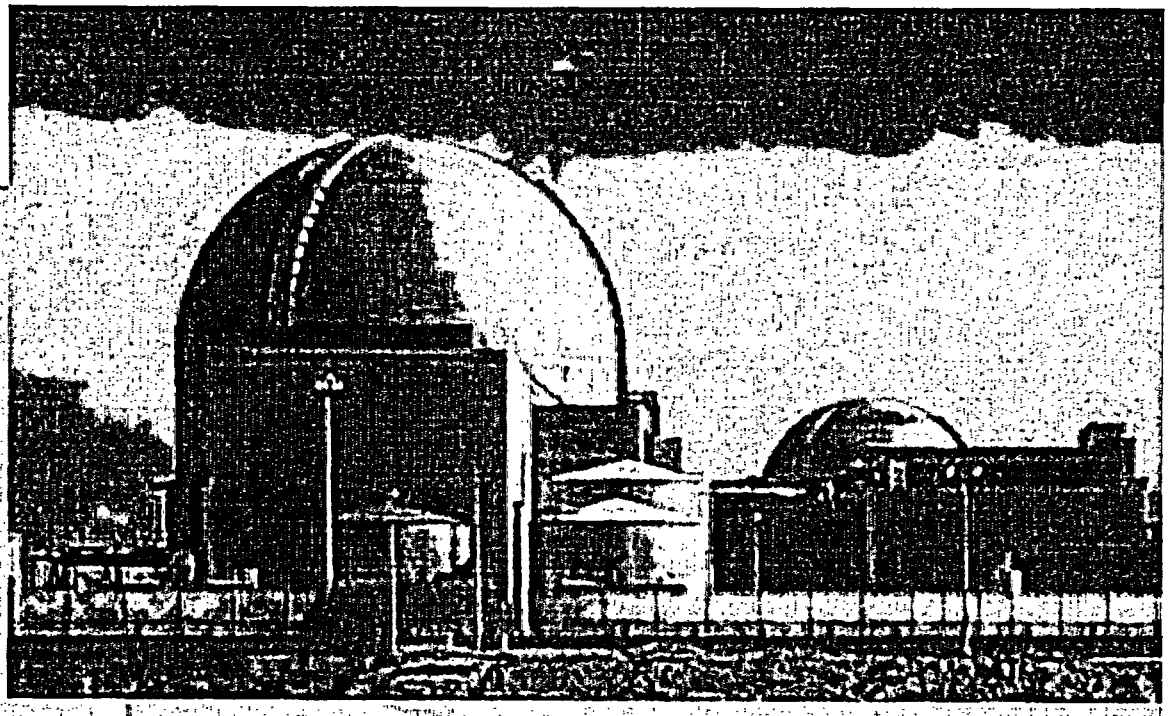
The Southern California Public Power Authority (SCPPA) was created in 1980 by all eleven of the public power systems in Southern California to provide financing for their participation in electric generating facilities and high voltage transmission lines. The SCPPA member systems include: the cities of Anaheim, Azusa, Banning, Burbank, Colton, Glendale, Los Angeles, Pasadena, Riverside, Vernon and the Imperial Irrigation District. The newest SCPPA member is the City of Cerritos. Together, these members serve over 2 **million** residential and business customers in Southern California representing a population of approximately 4.8 **million people.**

Collectively, **SCPPA's twelve members have several unique characteristics.** They are **non-profit** based, **governed locally,** have **direct participation** in the decision making process, and are committed and maintain the **obligation to serve** and consistently plan for all of the electric needs of the communities they serve. Throughout the California energy crisis, the only success story has been the public power systems through the diversity of their resources and investment in renewable energy sources. Over the years, the Southern California public power systems have invested in or have secured under long-term purchase contracts power generation transmission facilities throughout the West. These facilities provide not only the diversity of fuel and technology, but the location that has served SCPPA members well by providing constant and predictable electrical prices.

Traditional investments have been made in the areas of hydroelectric, nuclear, coal, and natural gas-fired generation. To meet the challenges and growing demand for energy needs, new investments in local base load and peaking natural gas-fired units will satisfy these needs and increase system reliability. In addition, new renewable projects will further diversify generation portfolios, and also benefit the environment through better pollution control technologies. When these projects are completed, SCPPA members will have installed in excess of 2,000 megawatts of new gas-fired generation, such as the Magnolia Power Project, to meet base load growth, peaking requirements, or retire older less efficient units. This investment, representing approximately $2 billion, illustrates how seriously SCPPA members take their obligation to serve and plan for the future of their customers.

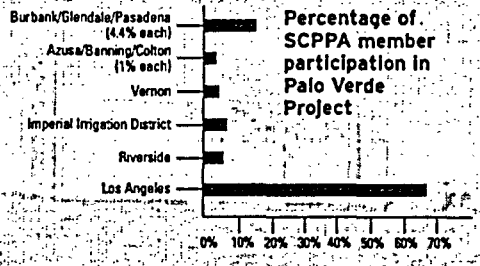
SCPPA members are well positioned to serve and meet their customer's energy needs today and in the future. Through the use of new investments in local base load and peaking natural gas-fired units and prudent use of electricity, **SCPPA, in partnership with its members, is leading the way to the future.**

Palo Verde Project



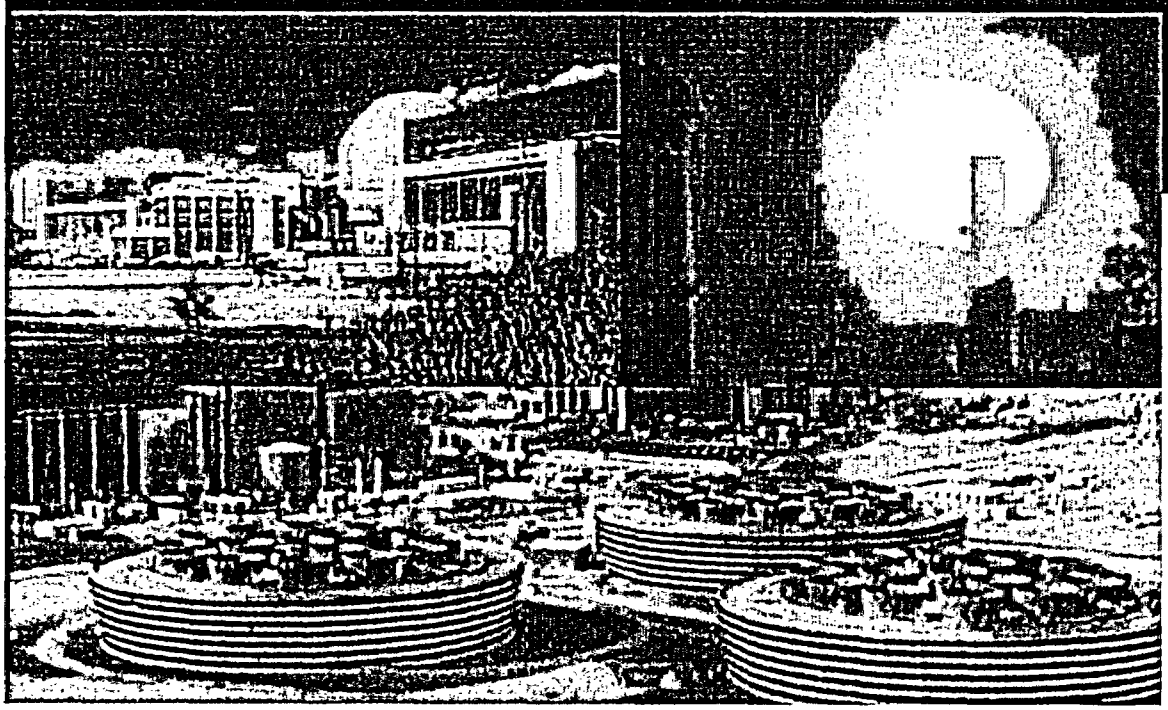
2002-2003 OPERATIONS

	Generation (Millions of MWHs)	Capacity Utilization (%)
Unit 1	9.5	86.9%
Unit 2	11.1	101.7%
Unit 3	9.8	90.0%
Aggregate	30.4	92.9%



Percentage of SCPPA member participation in Palo Verde Project

"Palo Verde set a national generation record of 30.8 million MWHs."



Palo Verde completed another high production year, surpassing a 90% capacity factor for the sixth consecutive year. SCPPA owns 5.91% of the station on behalf of 10 of its members.

Palo Verde Nuclear Generating Station continues to be the largest producer of electricity in the United States. During calendar 2002, Palo Verde set a national generation record of 30.8 million MWHs.

The Independent Spent Fuel Storage Installation (dry cask storage) was completed and began receiving spent fuel from the wet pool.

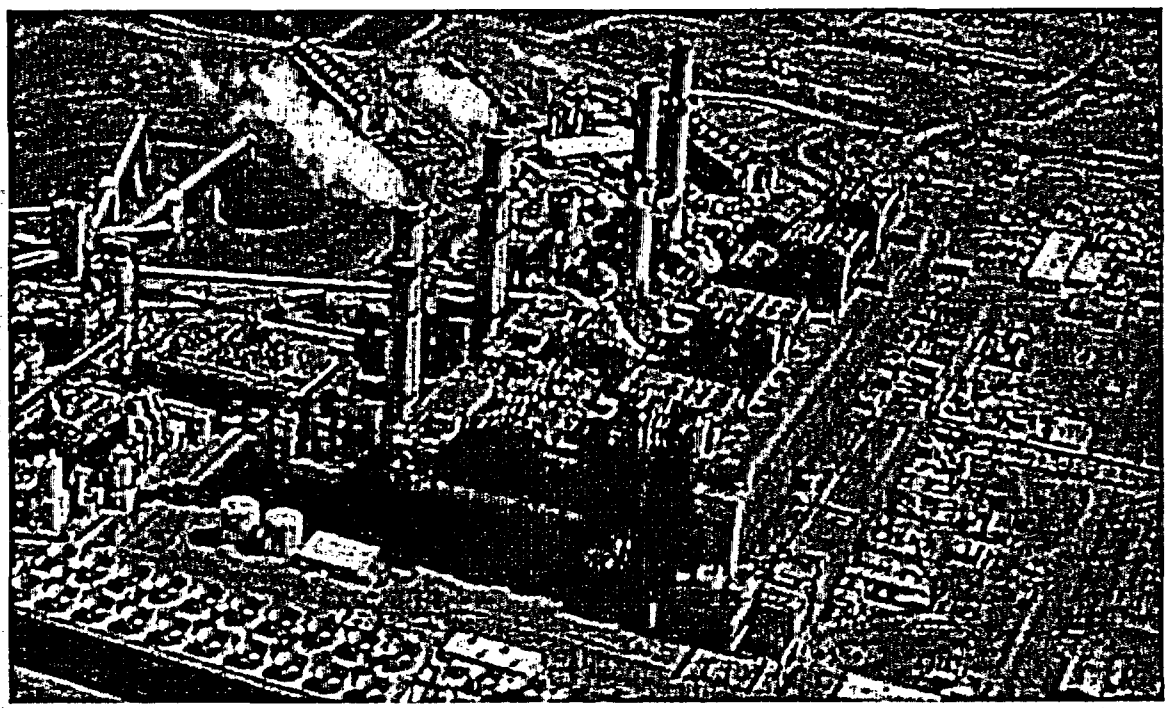
Palo Verde received its fifth consecutive INPO #1 rating (the highest possible) from the Institute of Nuclear Power Operations.

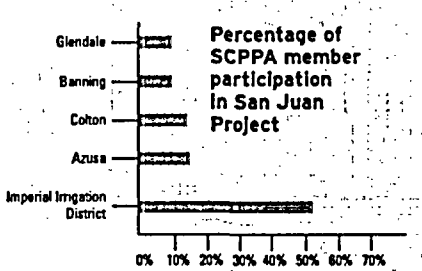
At the end of the fiscal year, preparations were being made for the replacement of Unit 2 steam generators in the fall of 2003. The replacement project and related modifications will result in a 92 MW capacity increase.

PRODUCTION COST
(Operation and Maintenance plus Nuclear Fuel)

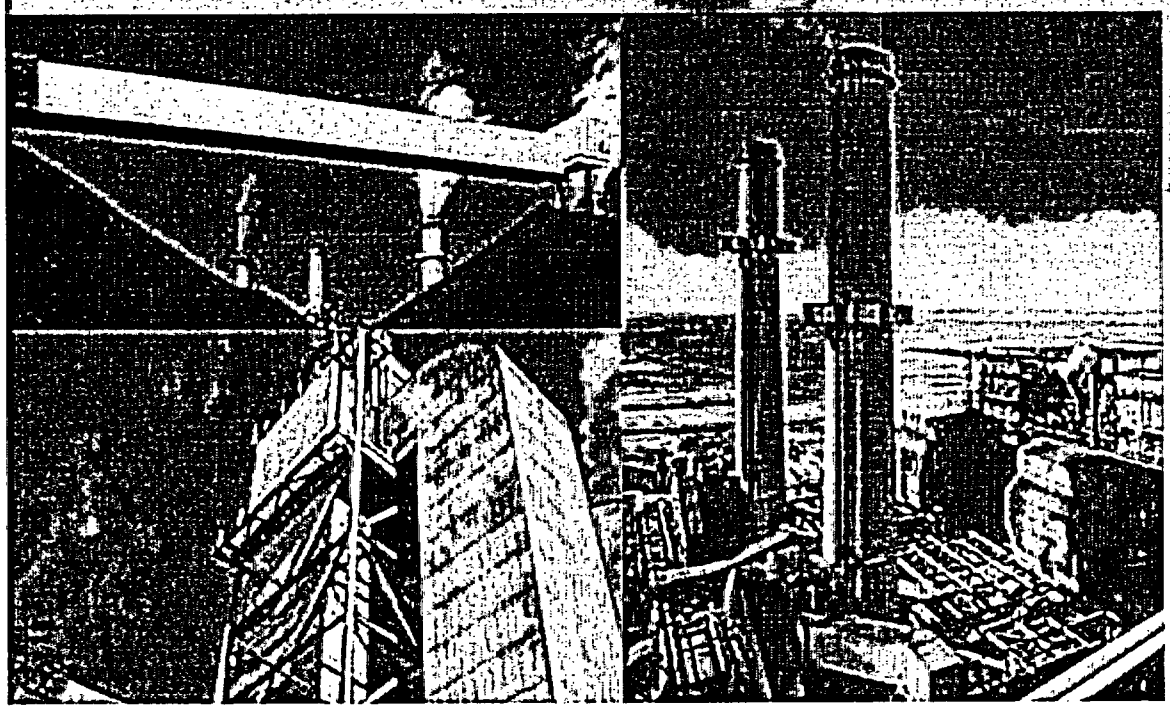
Calendar Year	Cents per kWh
1993	2.02
1994	1.93
1995	1.61
1996	1.45
1997	1.33
1998	1.28
1999	1.25
2000	1.25
2001	1.27
2002	1.28

San Juan Unit 3 Project





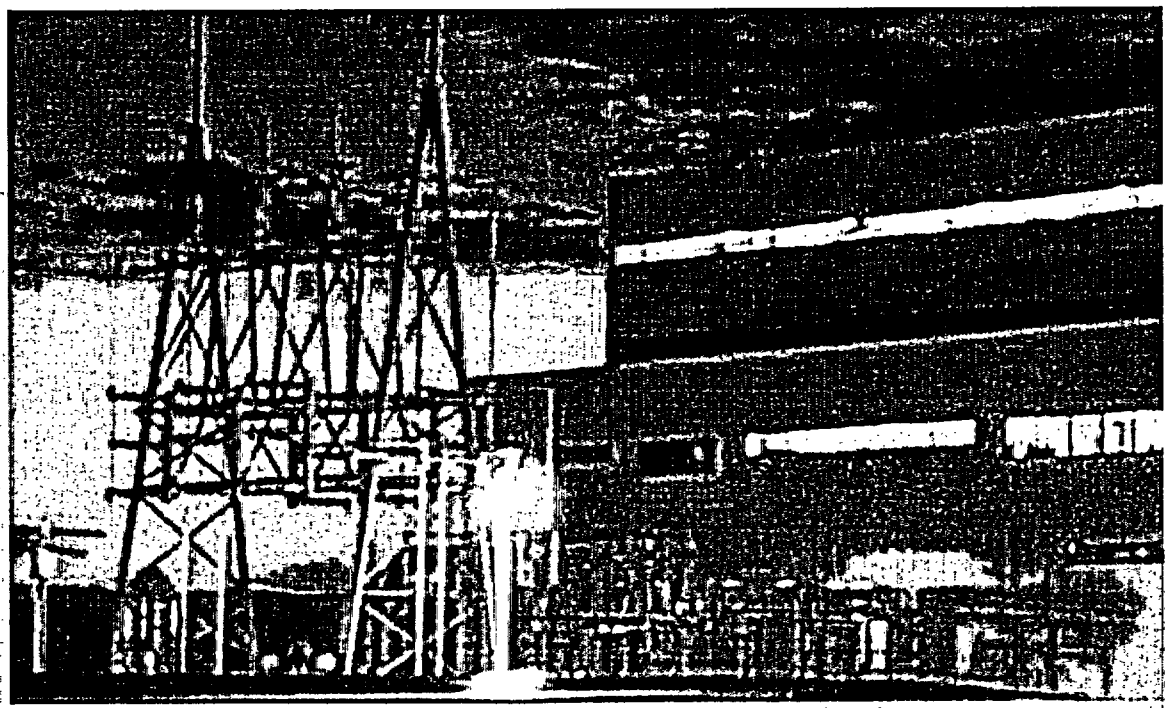
"Fuel from the underground mine will be both lower cost and lower ash, yielding added benefits in efficiency and maintenance costs."

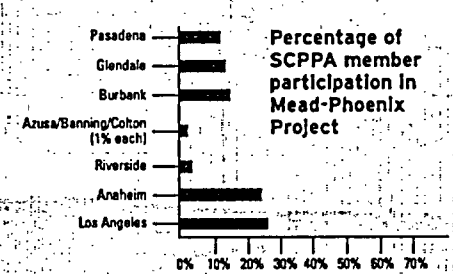


Five SCPPA participants own 41.8% of Unit 3 at the San Juan Generating Station, a coal-fired plant in New Mexico. A series of Interim Invoicing Agreements for fuel has led to high capacity factors and lower per unit fuel costs.

After two decades of surface strip mining at the adjacent coal mine, operations have transitioned to long-wall underground mining. Fuel from the underground mine will be both lower cost and lower ash, yielding added benefits in efficiency and maintenance costs.

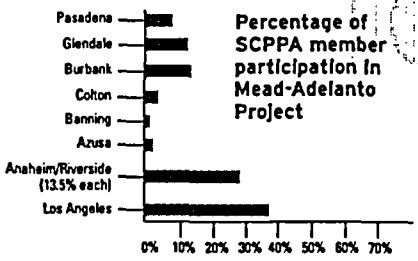
Mead-Phoenix/Mead-Adelanto Transmission Projects





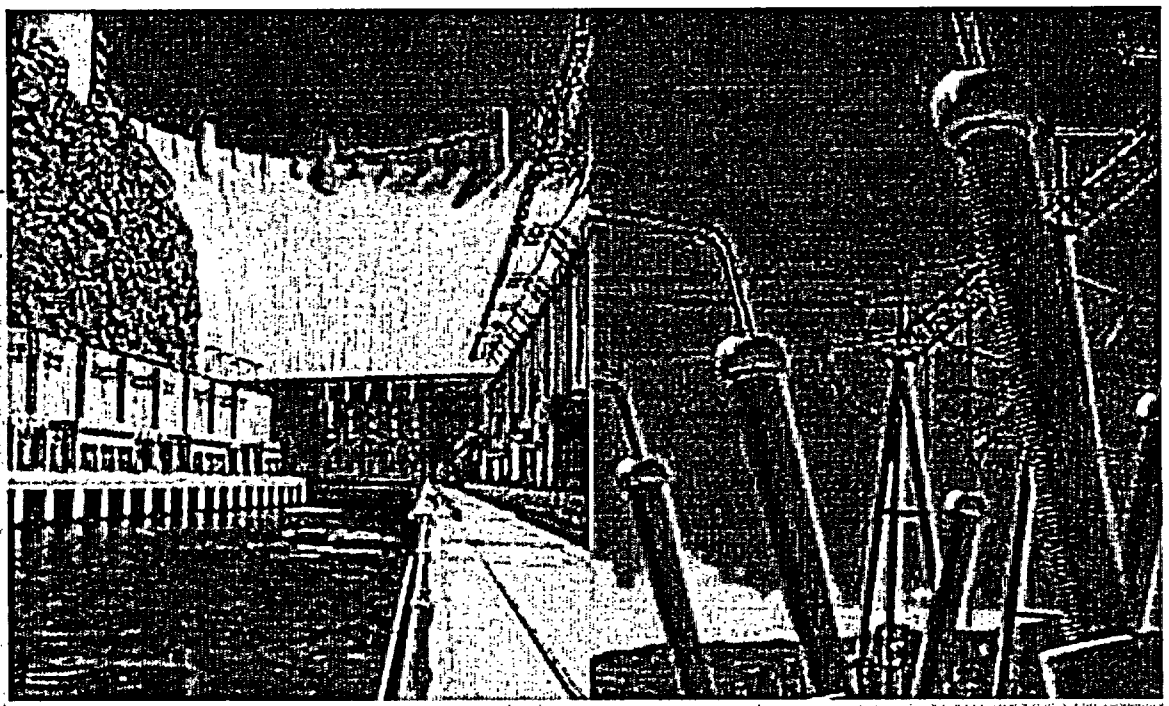
Percentage of SCPPA member participation in Mead-Phoenix Project

The two 500-kV transmission lines, which connect Phoenix to Las Vegas, and Las Vegas to Southern California, completed their sixth year of dependable operation for the nine SCPPA members who participate in the projects.

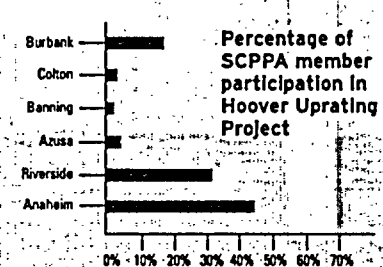


low-cost

Hoover Uprating Project



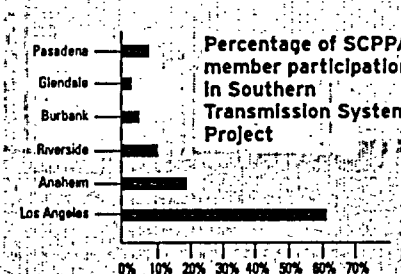
The Hoover Uprating Project continues to provide six SCPPA members with low-cost, renewable energy (hydro). A SCPPA representative is active in the development of the Lower Colorado River Multi-Species Conservation Program.



Percentage of SCPPA member participation in Hoover Uprating Project

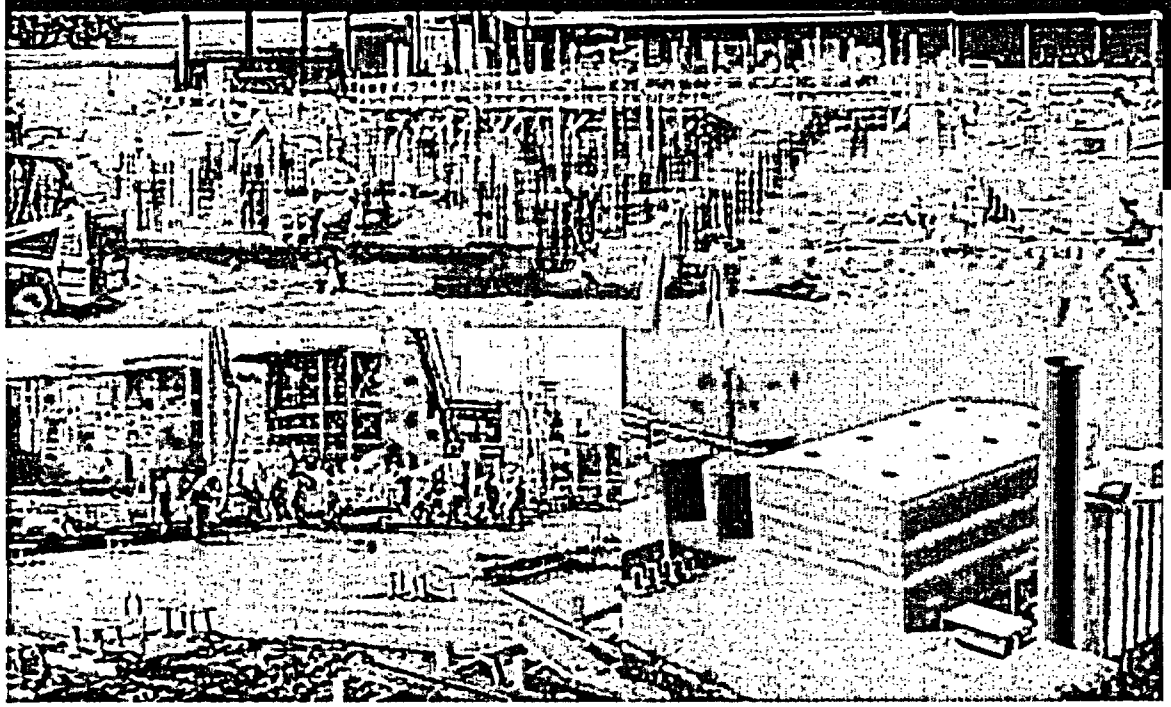
Southern Transmission System Project (STS)

As usual, the STS operated with near-perfect availability (99.54%), delivering over 14 million MWHs to the six SCPPA members who are participants. The power comes 488 miles from the Intermountain Power Project, in Utah, over the ±500-kV DC line.



Percentage of SCPPA member participation in Southern Transmission System Project

"The result will be more power from less fuel, with less pollution."

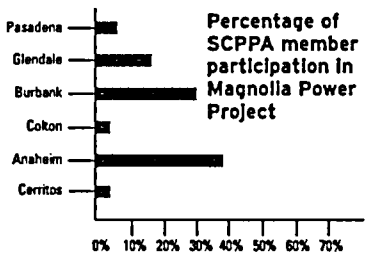


Magnolia Power Project

Construction has begun on the Magnolia Power Project, a 240 megawatt natural gas-fired, combined cycle plant, to be located on the site of an existing plant in the City of Burbank. It will replace an older, less-efficient, dirtier unit. The result will be more power from less fuel, with less pollution.

Licensing and financing were completed during the fiscal year, and the official groundbreaking was held on June 10, 2003. The plant could be operational by spring of 2005, and will be the first project to be wholly-owned by SCPPA members. The participants are Anaheim, Burbank, Cerritos, Colton, Glendale, and Pasadena.

The ground breaking shovels are put to work by project participant representatives in planting a dwarf magnolia tree to symbolize the start of 24 months of MPP site work.



Financing Activities

"SCPPA's Finance Committee continues to look for opportunities to lower financing costs through bond refunding and escrow restructuring."

STS Project 2002 Series B Bond Refunding
On October 1, 2002, SCPPA sold $38,755,000 Southern Transmission System Project 2002 Refunding Series B subordinate lien bonds maturing 2007 through 2012 at a true interest cost of 3.48 percent. The bond proceeds, along with other sources of funds amounting to $7,308,028, were used to current refund, on December 26, 2002, $46,400,000 bonds (the Residual Interest Bonds and Select Auction Variable Rate Securities (together the "RIBS/SAVRS")) maturing in 2012, as part of the Project's 1992 issue. The RIBS were called at a redemption price of 104 percent and the SAVRS were called at par. Together the RIBS/SAVRS (which share a combined coupon of 6%) were called at a redemption price of 102 percent. Net present value savings from the transaction, after adjusting for forgone interest earnings on prior funds on hand, amounted to $5,675,172, or 12.23% of the bonds refunded. Bear Stearns senior managed the transaction with Loop Capital Markets and Salomon Smith Barney acting as co-managers. The triple-A rated bonds were issued by Financial Security Assurance, Inc. Underlying ratings of A1 and A+ were assigned to the bonds by Moody's and S&P, respectively.

San Juan Project Unit 3 Bond Refunding
On October 24, 2002, SCPPA sold $71,850,000 San Juan Power Project Revenue Bonds, 2002 Refunding Series B, to UBS PaineWebber, Inc. The bonds, referred to as Auction Rate Certificates (ARCs), have an initial fixed interest rate to January 1, 2012, after which the ARCs will bear variable rates to their maturity in 2020. The ARCs were sold with a coupon of 5.25%, priced to yield 3.65% with a true interest cost of 3.86%. They will replace the 5.00%, $70,800,000 bonds from the Project's 1993 issue. The refunding net present value savings were $8,131,998, representing 11.48% of the refunded bonds. An investment agreement for the refunding debt service reserve account was entered into with triple-A rated AIG Matched Funding Corp. with a winning bid of 4.442%. The bonds were insured by Financial Security Assurance, Inc. and were assigned triple-A ratings from Moody's Investors Service and Standard & Poor's. Underlying ratings of A2 and A+ were assigned to the bonds by Moody's and S&P.

Palo Verde Escrow Restructuring
In February 2003, SCPPA closed an escrow restructuring associated with the Project's 1997 Subordinate Refunding Series B bonds, and the refunded Project Revenue Bonds, 1993 Refunding Series A and the 1993 Subordinate Refunding Series. The restructuring involved liquidation of open-market Refcorps securities; the redemption of SLGS interest-bearing and zero coupon securities; the partial termination of a Float Forward Agreement with Lehman Brothers Special Financing, Inc. (at a cost of $3,509,000); the purchase a of U.S. Treasury Note; and the redemption of defeased Series 1993 Bonds on July 1, 2003. Utilizing a competitive bid process for the sale of securities and the purchase of a replacement security, net present value cash savings in the amount of $16,696,539 were achieved from the restructuring after payment of the Float Forward Agreement breakage fee to Lehman. SCPPA entered into agreements with UBS PaineWebber, Inc. and Public Financial Management, Inc. to execute the restructuring.

Magnolia Power Project Financing
On April 2, 2003, SCPPA successfully financed its new Magnolia Power Plant, a natural gas-fired, high-efficiency, combined-cycle generating facility with a nominally rated net base capacity of 240 MW that is being constructed in Burbank. The bonds were sold in two series consisting of $299,975,000 Project A bonds, secured by take or pay power sales agreements with Anaheim, Burbank, Colton, Glendale and Pasadena, and $14,105,000 Project B bonds, secured by base rental payments by Cerritos from its general fund and other legally available funds under a lease agreement with SCPPA. The combined Project bonds, maturing in 2036, were sold at an all-in true interest cost of 4.910%. The triple-A bonds were insured by Ambac Assurance Corporation, and underwritten by co-senior managers UBS PaineWebber, Inc., (as book runner) and Salomon Smith Barney, with co-managers Bank of America Securities, LLC, Banc One Capital Markets, Inc., Bear Stearns & Co., Inc., Samuel A. Ramirez & Co., Inc., and Siebert Brandford Shank & Co., LLC. Underlying ratings of A1 and A+ were assigned the Project A bonds by Moody's and S&P, respectively. S&P assigned an underlying rating of AA+ to the Project B bonds.

STS Project 2003 Series A Bond Refunding
In connection with the issuance of the 2003 Auction Rate Security (ARS) revenue bonds, two transactions took place. On April 24, 2003 SCPPA entered into a 65 percent of LIBOR floating-to-fixed forward interest rate swap with Citigroup Financial Products, Inc. The purpose of the forward swap was to lock in favorable interest rates. The forward start 19-year (16.9-year weighted average life of bonds) interest rate swap replaced an average coupon bond rate of 5.07 percent with a fixed rate of 3.266% that SCPPA will pay Citigroup and in return receive 65% of 1-month LIBOR. On May 20, 2003, SCPPA sold $51,750,000 Southern Transmission System Project Revenue Bonds, 2003 Subordinate Refunding Series A, as Auction Rate Securities (ARS) to Citigroup. The bond proceeds, along with other sources of funds amounting to $10,094,935, were used to current refund, on July 1, 2003, $58,495,000 1993 Subordinate bonds maturing 2003 to 2023. Most of the 1993 Subordinate bonds were called at par, with the balance called at 102 percent. Net present value savings from

Financing Activities (continued)

the transaction, after adjusting for forgone interest earnings on prior funds on hand, amounted to $6,937,640, or 11.86% of the bonds refunded. Citigroup Global Markets, Inc. was the underwriter for the transaction. The triple-A rated bonds were insured by MBIA Insurance Corporation. Underlying ratings of A1 and A+ were assigned to the bonds by Moody's and S&P, respectively.

Other Refundings

SCPPA's Finance Committee continues to look for opportunities to lower financing costs through bond refundings and escrow restructurings. At year-end, refundings of additional San Juan and Mead Adelanto/Mead Phoenix Project bonds were under consideration.

As of June 30, 2003	Bond Ratings	
SCPPA BONDS	Moody's Investors Service	Standard & Poor's
Hoover Uprating Project[1]	Aa3	AA-
Southern Transmission System		
Senior Lien Bonds	Aa3	AA-
Subordinate Lien Bonds[2]	Aaa/VMIG1	AAA/A-1+
Subordinate Lien (underlying)	A1	A+
Palo Verde Project[3]		
Senior Lien Bonds	A2	AA-
Subordinate Lien Bonds	Aaa/VMIG1	A+
Multiple Project Revenue Bonds		
Mead-Adelanto	Aa3	-
Mead-Phoenix	Aa3	-
Multiple Project[4]	A2	A
Mead-Adelanto Revenue Bonds[5]	Aaa	AAA
Mead-Phoenix Revenue Bonds[5]	Aaa	AAA
San Juan Unit 3[6]	Aaa	AAA
San Juan Unit 3 (underlying)	A2	A+
Magnolia Power Project A[7]	A1	A+
Magnolia Power Project B[7]	-	AA+

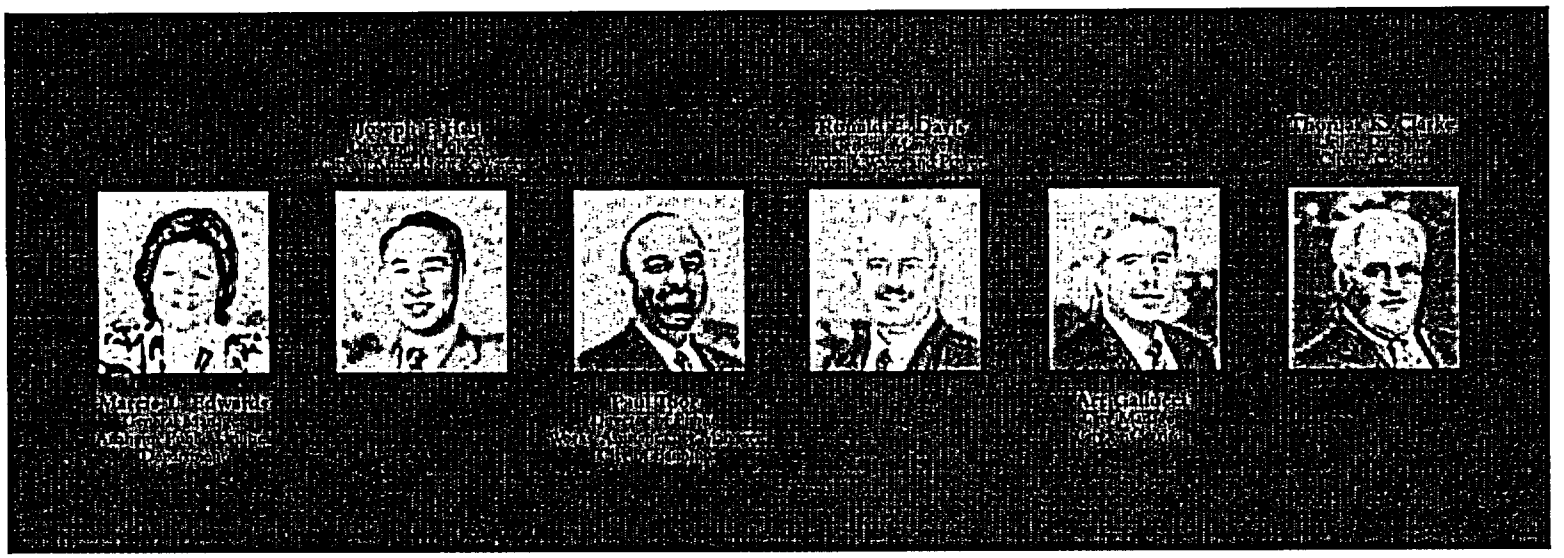
[1]Insured: 2001 Refunding Series A (FSA)
[2]Insured: 1991 Subordinate Variable Rate Bonds (AMBAC); 1993 Subordinate Series (MBIA); 1996 Subordinate Series A Bonds (MBIA); 1996 Subordinate Variable Rate Series B Bonds (FSA); 1998 Subordinate Series A (MBIA); 2000 Subordinate Variable Rate Series A Bonds (FSA); 2001 Subordinate Series A (FSA); 2002 Subordinate Series A (FSA); 2002 Subordinate Series B (FSA).
[3]Insured: 1992 Senior Lien Bonds (AMBAC); 1993 Subordinate Bonds (FGIC); 1996 Subordinate Series A (AMBAC); 1996 Subordinate Variable Rate Series B and C Bonds (AMBAC); 1997 Subordinate Series A and B Bonds (FSA); Installment Deposits to Defease the 1987 and 1989 Bonds (FSA); 1999 Subordinate Refunding Series A Bonds (FSA).
[4]Uncommitted bond proceeds secured by a guaranteed rate investment contract.
[5]Insured: 1994 Series A Bonds (AMBAC).
[6]Insured: 1993 Series A Bonds (MBIA); 2002 Refunding Series A (FSA).
[7]Insured (AMBAC)

SCPPA Legislative Report

California's governor, as well as the state Senate and Assembly, were forced to face a budget crisis during this first year of the new two-year legislative session. The combination of mismanagement of the state's 2003 budget crisis and the electricity crisis of 2000-01 resulted in the October 7th recall and ouster of Democrat Governor Gray Davis, replacing him with Republican Arnold Schwarzenegger. For the first time in nearly three years, however, the legislature did not face urgent electricity issues. Regardless, several legislative proposals contained weighty policy shifts requiring SCPPA action, either supporting or opposing individual proposals.

Rarely in the legislative arena does a proposal emerge to gather support based purely on public policy since it is the right position to take, irrespective of benefits or lack thereof. Support for Senate Bill 888 (Dunn) by SCPPA and its member utilities is one of those instances. Our combined support became critical to the bill's survival through its thorny, yet unfinished legislative journey. SB 888 represents a major policy step toward correcting the failures of electricity restructuring and AB 1890. In 1996, California's municipal utilities, guided by the wisdom of local officials who govern and set rates, were unconvinced of the promised benefits of deregulation and its business model, requiring investor-owned utilities to sell the assets that produced the product sold. SB 888 once again confirms the traditional regulatory compact for investor-owned utilities. SB 888's concepts are clear – to investor-owned utilities, it restores the obligation to serve, including the obligation to plan for the future electricity needs. Planning encompasses utility ownership and procurement of generation, transmission and distribution resources. It requires that generation assets are dedicated to the consumers who pay for them. The California Public Utilities Commission's (CPUC) mandated role is to assure that investor-owned utilities have the ability to meet their obligation to serve. The bill stalled in the Assembly and is pending action next year. Its legislative future and the stability it would offer to California's electricity market are uncertain.

For a second year, legislation focused on the Magnolia Power Plant project was introduced. Last year's Assembly Bill 80 (Havice) authorized cities participating in the Magnolia Power Plant project to aggregate their electricity loads and provide direct access to their residents and was signed by the Governor on September 24, 2002. The 2003 proposal, AB 1169 (Bermudez), would allow municipal entities participating in the Magnolia Power Plant project to provide electricity to local public agencies located within or contiguous to a project city's jurisdiction. Because the bill is not definitive, it would apply to any project participant as provided by lease revenue bonds. AB 1169 is pending in the Senate Energy, Utilities and Communications Committee and could be reactivated in January. SB 520, sponsored by the California Municipal Utilities Association and supported by SCPPA and its members, would have required the Independent System Operator (ISO) to conduct an internal performance review and operational cost analysis. The ISO would then submit a report on its findings and conclusions to the legislature. The purpose of the review would be to compare the California ISO's costs with system operators in other states. The bill failed in the Senate policy committee. AB 1051 (Goldberg), sponsored by the City of Los Angeles, redefines capital facilities fee to mean any nondiscriminatory charge imposed to pay for public utility facilities, not to exceed reasonable costs; unfortunately Governor Davis vetoed the bill.



SCPPA Municipalities

City of Anaheim Innovative solutions designed to meet the energy needs of a dynamic community have been a hallmark of Anaheim Public Utilities since its inception in 1894. Today, the City of Anaheim is the only community in Orange County with a publicly owned water and electric utility. Anaheim residents enjoy rates that are significantly lower than the electric rates charged in neighboring communities, reliable electric service, and an array of more than 40 targeted energy efficiency programs. In the coming years, Anaheim Public Utilities will continue to work to the best advantage of Anaheim consumers. With a strong, creative management team, sound resource and financial planning, and a cadre of experienced and dedicated employees, we will maintain sharp focus on meeting the community's long-term power needs and offer measures that will help our customers make efficient use of electricity.

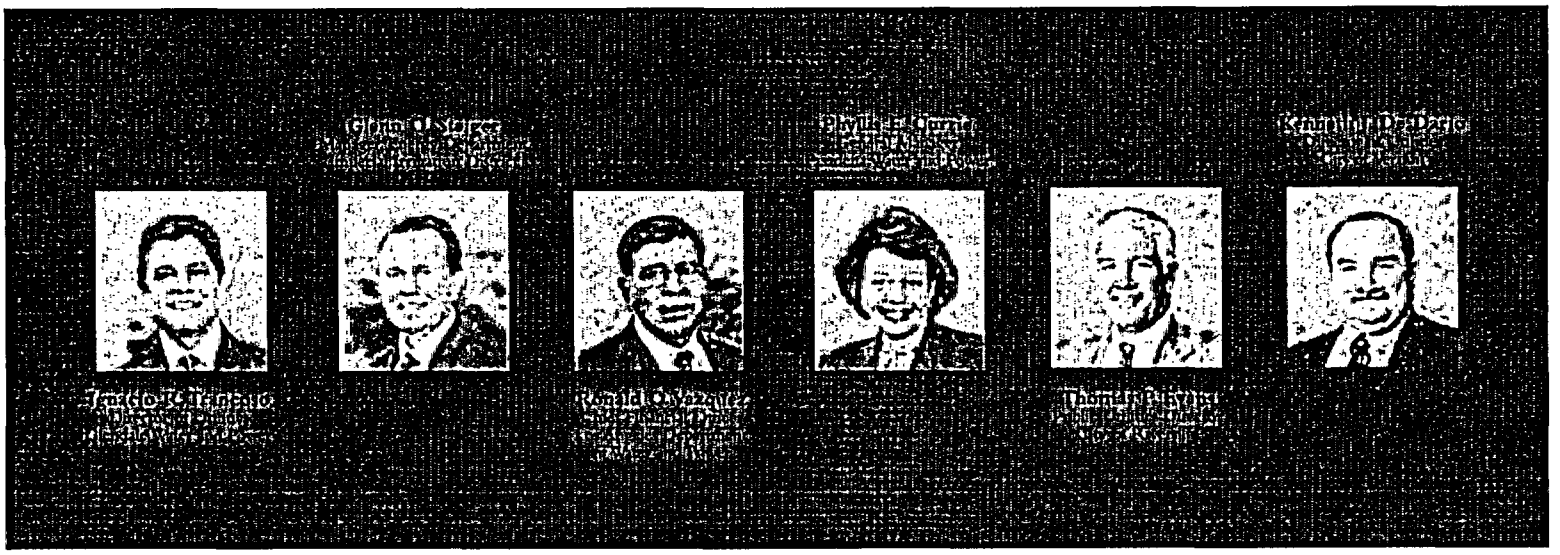
City of Azusa The City's electric utility was incorporated in 1898 when it purchased the assets of a private utility on the brink of bankruptcy. The foresight and planning of those early pioneers continues to be the cornerstone of today's Azusa Light and Water. Diligent planning of system improvements and power resource procurement has enabled Azusa Light and Water to maintain retail rate stability and competitiveness despite the turmoil in the industry in recent years. Azusa Light and Water has also been recognized as one of the proactive leaders in prompting energy conservation and efficiency programs and renewable energy in the State, earning the recognition of CMUA 2002 Community Services/ Resource Efficiency Award for its "2001 Load Reduction Program" and being one of the first utilities in procuring renewable energy from High Winds windpower project, which is expected to provide up to 8% of Azusa's annual retail load requirement, and thus substantially exceeding SB 1078's mandate.

City of Banning Established in 1913, the Banning electrical system now serves an area of approximately 22 square miles. The City continues to optimize its power resources through innovative planning. Banning's energy resource base includes portions of coal, nuclear and hydro generating plants, which provide the majority of electricity required to meet its summer peak load of 42 MW. The Utility has further improved its service and reliability through significant upgrades to its distribution system, and is committed to continue providing quality service to its customers in a reliable manner, and at reasonable rates.

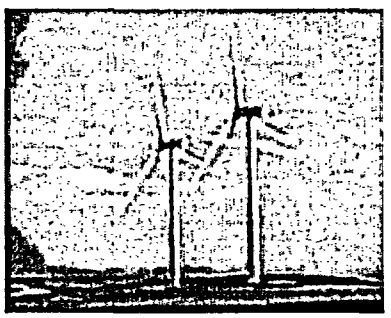
City of Burbank Burbank Water and Power began serving both water and electric customers in 1913 and installed on-site generation in response to a surge in industrial and residential growth in the 1940s and 1950s. Today the City receives power from three SCPPA projects, as well as firm and interruptible supplies from other utilities and government agencies, and continues to operate its own local power plants.

City of Cerritos The first new member to join Southern California Public Power Authority in over 20 years, the City of Cerritos is preparing to serve the electricity demands of its residential and business communities. To further these efforts, Cerritos is participating in the development of the Magnolia Power Project. With the goal of providing a stable and affordable supply of electricity, Cerritos intends on developing a diverse portfolio of power to be delivered as competitively and economically as possible.

City of Colton The Colton Municipal Utility was established in 1895 and has provided our customers with reliable and affordable electric service for over one hundred years. We are proud of this accomplishment, and have positioned ourselves to continue this high level of service over the next century. By making firm commitments for resource planning, system maintenance, community involvement, and employee enrichment, we believe this pledge to our customers will provide the value that they deserve.



City of Glendale Incorporated in 1906, Glendale purchased its electric utility in 1909, obtaining power from outside suppliers. It received its first power from Hoover Dam in 1937 and inaugurated the first unit of its own steam generating plant in 1941. Now called the Grayson Power Plant, this facility today has eight generating units. Glendale continues to purchase 85 percent of its power from outside sources.



Imperial Irrigation District IID entered the power industry in 1936 and today serves a peak load of 704 MW with 850 MW of generating resources. Among IID-owned resources are 24 MW of low head hydro units along the All American Canal, 307 MW of gas-fired steam and combined cycle units, and 162 MW of peaking gas turbines. In addition to IID's share of SCPPA resources comprising 104 MW at San Juan and 14 MW at Palo Verde, IID has 179 MW of other resources under long-term purchase contracts.

Los Angeles Department of Water and Power Providing service for more than a century, the Los Angeles Department of Water and Power began delivering water to the city in 1902, and with the water came power. In 1916, LADWP first delivered electicity to the city purchased from the Pasadena Municipal Plant. A year later, LADWP began generating its own hydro-electric power at the San Francisquito Power Plant No. 1. After purchasing the remaining distribution system of Southern California Edison within the city limits in 1922, LADWP became the sole water and electricity provider for the City of Los Angeles. It is now the largest municipally owned electric utility in the nation, serving a population of 3.8 million residents over a 464 square mile area. LADWP remains on firm financial footing and serves as a valuable asset to the City of Los Angeles.

City of Pasadena Established in 1906, the city built its first electric generating steam plant in 1907 and took over operation of its municipal street lighting from Edison Electric. In 1909, Pasadena began the extension of its operations to commercial and residential customers that resulted in the replacement of all Edison Electric service in the city by 1920.

City of Riverside The City of Riverside Public Utilities provides electric service to more than 98,000 metered accounts, representing a service area population of over 274,000. The utility is committed to the highest quality water and electric services at the lowest possible rates to benefit the community. To maintain their commitment, Riverside has positioned itself well in the electric market by utilizing short, mid, and long term contracts from power suppliers, and by building power generation sources with its own power grid, including a 40 MW power plant in 2002. Riverside's portfolio includes 28 MW of renewable resources which includes 350 kW of photo-voltaic systems within the City.

City of Vernon Vernon's Utilities Department began serving industrial customers in 1933, with completion of its diesel generating plant. In addition to its own power from diesel units and gas turbines, Vernon also receives power from Palo Verde, Hoover, and various suppliers. Vernon also is in the process of constructing a 134 MW gas-fired combined cycle power plant within its city limits. Vernon resides within the California Independent System Operator (CAISO) Control Area and is a Participating Transmission Owner.

SCPPA Legislative Report (continued)

Replacing the authority of local government decision-making with mandatory state standards for the purchase of renewable resources for generating electricity remains a threat for municipal utilities. SCPPA members continue to assert that such decisions are and should remain with local elected officials who, along with the community's consumers, determine the mix in their generation portfolio. Though no legislation emerged this year, threats of amendments to force community-owned utilities to meet state renewable portfolio standards were constantly looming and could have been added to several of the bills included in this writing. Committed to acquiring resources sensitive to the environment and air quality concerns, SCPPA members continue to build and purchase renewable assets as well as argue the need to include large hydroelectric investments in the definition of qualifying renewable resources.

SCPPA, its members and other California municipal utilities were also active in their opposition to legislation. AB 816 (Reyes) would impose exit fees on new and existing consumers purchasing electricity service from a municipal utility. SCPPA's position on the bill is unambiguous: customers who move into a new development in local publicly owned utility service territory and were never served by an IOU should not pay any exit fees. A second, equally contentious issue addressed by AB 816 would reinstate direct access, the right of retail end use customers to acquire electricity service from suppliers other than investor-owned utilities. The bill stalled in the Senate, but is subject to action in early 2004. SB 18 (Burton) failed in the Assembly during the final day of this year's legislative session. The bill would create a procedure to determine whether a proposed project may adversely change a traditional tribal cultural site and recommend project changes and mitigation measures to avoid or reduce those changes.

The direction of the new governor's electricity policy is at this writing still being developed. What is certain is SCPPA remains committed to building and acquiring generation assets for its members, with particular commitment to renewable generating assets. This commitment along with the combined influence of SCPPA and its members culminates in a common voice on issues on vital electricity policy issues in Sacramento and Washington, D.C., providing greater influence by public power.

In Washington, D.C., Congress tried but failed to pass a comprehensive energy bill that included significant changes in federal electricity policy. Despite strong support from the White House and the Republican leadership in the House and Senate, the final version of the bill proved to be too costly and too controversial to win the 60 votes needed to end a filibuster by Democratic and Republican opponents. Following the failed closure vote, the Senate leadership pulled the bill but pledged to return to it in January, 2004. Given the significant regional differences that emerged on several key issues, it remains to be seen whether Congress can craft a consensus and pass a broad-based energy bill, particularly in a presidential election year. From the point of view of SCPPA member utilities and the consumers they serve, the demise of the energy bill is a good result. Although the electricity title had some positive provisions for consumer-owned utilities, its overall impact on SCPPA members would have been more negative than positive.

On the positive side, the bill authorized voluntary – not mandatory – Regional Transmission Organizations (RTOs) and expressly stated that the Federal Energy Regulatory Commission (FERC) could not order unregulated public power systems and federal utilities into an RTO. SCPPA strongly supported both of those concepts. In other ways, however, the bill significantly encroached upon public power's local control. For example, the bill gave FERC new authority over transmission facilities owned and operated by consumer-owned and federal utilities (the so-called "FERC Lite" provision) and new authority to order refunds of short-term wholesale power sales by large public power systems if market rules are violated. These provisions would have substituted decisions of FERC for the judgments of local officials and utilities. While SCPPA endorsed the bill's delay of FERC's complex new rules on Standard Market Design (SMD), the delay did not apply to the California ISO's Market Design 2002 (MD 02) initiative. Thus, the delay provision provided no benefits for California municipal utilities that believe the ISO should proceed more cautiously with market protocols and rules that differ from those in the rest of the Western market.

Also of concern to SCPPA, the bill repealed the Public Utility Holding Company Act (PUHCA), a 1935 law designed to protect investors and consumers against the risks of holding company diversifications and other transactions. PUHCA also provides barriers to mergers that SCPPA believes promote competition. To mitigate the impact of PUHCA repeal, SCPPA and other consumer interests advocated giving FERC stronger merger review authority and power to deal effectively with market manipulation and deception. Unfortunately, the final version of the energy bill contained none of these additional consumer protection.

Finally, in the last stage of congressional negotiations on the energy bill, the tradable tax credits for consumer-owned electric utilities that develop renewable resources were deleted. Elimination of the tradable tax credits puts SCPPA members and other public power systems at a distinct economic disadvantage, vis-à-vis private power companies, which benefit from automatic tax credits that effectively "buy down" the cost of new renewable energy projects. Its elimination was another key reason that SCPPA found the final energy bill wanting. Because the issues at stake in the energy bill are so critical for SCPPA members, we spent considerable time and resources in Washington, D.C. in 2003, working with members of the California congressional delegation and others to inform them of the impact of the electricity title on consumers in Southern California. If Congress takes up the energy bill again in the second session of the 108th Congress, SCPPA will again mount a vigorous effort to protect and promote local control and the interests of the approximately two million consumers we serve.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED FINANCIAL STATEMENTS
INDEX

The following discussion and analysis of the financial performance of each of the projects in which the Southern California Public Power Authority (the "Authority" or "SCPPA") has interests, provides an overview of the projects' financial activities for the fiscal year ended June 30, 2003. Descriptions and other details pertaining to the projects are included in the Notes to Combined Financial Statements. Please read this discussion and analysis in conjunction with the Authority's Combined Financial Statements, which begin on page 40.

The Authority is a joint powers authority whose primary purpose has been to provide joint financing for its member agencies that consist of eleven municipal electric utilities and one irrigation district in California. On a combined basis, these entities provide electricity to more than 2 million retail electric customers. A Board of Directors (the "Board") governs the Authority, which consists of one representative from each member agency. Two new member agencies, the Cities of Cerritos and San Marcos, joined the Authority in July 2001.

In August 2003, the Authority by a Board resolution rescinded the membership of the city of San Marcos, as the city no longer met the criteria for membership.

The Authority has interests in the following projects:

Palo Verde Project – On August 14, 1981, the Authority purchased a 5.91% interest in the Palo Verde Nuclear Generating Station ("PVNGS"), a 3,810 megawatt nuclear-fueled generating station near Phoenix, Arizona, and a 6.55% share of the right to use certain portions of the Arizona Nuclear Power Project Valley Transmission System (collectively, the "Palo Verde Project"). Units 1, 2 and 3 of the Palo Verde Project began commercial operations in January 1986, September 1986, and January 1988, respectively.

Southern Transmission System Project – On May 1, 1983, the Authority entered into an agreement with the Intermountain Power Agency ("IPA") to defray all the costs of acquisition and construction of the Southern Transmission System Project ("STS") which provides for the transmission of energy from the Intermountain Generating Station in Utah to Southern California. STS commenced commercial operations in July 1986. The Department of Water and Power of the City of Los Angeles ("LADWP"), a member of the Authority, serves as project manager and operating agent of the Intermountain Power Project ("IPP").

Hoover Uprating Project – As of March 1, 1986, the Authority and six participants entered into an agreement pursuant to which each participant assigned its entitlement to capacity and associated firm energy to the Authority in return for the Authority's agreement to make advance payments to the United States Bureau of Reclamation ("USBR") on behalf of such participants. The Authority has an 18.68% interest in the contingent capacity of the Hoover Uprating Project ("HU").

Mead-Phoenix and Mead-Adelanto Projects – As of December 17, 1991, the Authority entered into an agreement to acquire an interest in the Mead-Phoenix Project ("Mead-Phoenix"), a transmission line extending between the Westwing substation in Arizona and the Marketplace substation in Nevada. The agreement provides the Authority with an 18.31% interest in the Westwing-Mead project component, a 17.76% interest in the Mead Substation project component and a 22.41% interest in the Mead-Marketplace project component.

As of December 17, 1991, the Authority also entered into an agreement to acquire a 67.92% interest in the Mead-Adelanto Project ("Mead-Adelanto"), a transmission line extending between the Adelanto substation in Southern California and the Marketplace substation in Nevada. Funding for these projects was provided by a transfer of funds from the Multiple Project Fund and commercial operations commenced in April 1996. LADWP serves as the operations manager of Mead-Adelanto.

Multiple Project Fund – During fiscal year 1990, the Authority issued Multiple Project Revenue Bonds for net proceeds of approximately $600 million to provide funds to finance costs of construction and acquisition of ownership interests or capacity rights in one or more, then unspecified, projects for the generation or transmission of electric energy. Certain of these funds were used to finance the Authority's interests in Mead-Phoenix and Mead-Adelanto.

San Juan Project – Effective July 1, 1993, the Authority purchased a 41.80% interest in Unit 3 and related common facilities, of the San Juan Generating Station ("SJGS") from Century Power Corporation. Unit 3, a 488 megawatt unit, is one unit of a four-unit coal-fired power generating station in New Mexico.

Magnolia Power Project ("The Project") – In March 2003, the Authority received approval from the California Energy Commission for construction of the Magnolia Power Project. The Project will consist of a combined cycle natural gas-fired generating plant with a nominally rated net base capacity of 242 megawatts and will be built on a site in the City of Burbank, California. The plant is the first that is wholly owned by the Authority and entitlements to 100% of the capacity and energy of the Project have been sold to six of its members. The City of Burbank, a Project participant, will manage its construction and operation. Construction is under way and commercial operation is expected to begin in mid-2005.

Projects' Stabilization Fund – In fiscal year 1997, the Authority authorized the creation of a Projects' Stabilization Fund. Deposits may be made into the fund from budget under-runs, after authorization of individual participants, and by direct contributions from the participants. Participants have discretion over the use of their deposits within SCPPA project purposes. This fund is not a project-related fund; therefore, it is not governed by any project Indenture of Trust.

The members participate in the Projects' Stabilization Fund by making deposits to the fund at their discretion.

Participant Ownership Interests – The Authority's participants may elect to participate in the projects. As of June 30, 2003, the members have the following participation percentages in the Authority's interest in the projects:

Participants	Palo Verde	STS	Hoover Uprating	Mead-Phoenix	Mead-Adelanto	San Juan	Magnolia Power Project
City of Los Angeles	67.0%	59.5%		24.8%	35.7%		
City of Anaheim		17.6%	42.6%	24.2%	13.5%		38.0%
City of Riverside	5.4%	10.2%	31.9%	4.0%	13.5%		
Imperial Irrigation District	6.5%					51.0%	
City of Vernon	4.9%						
City of Azusa	1.0%		4.2%	1.0%	2.2%	14.7%	
City of Banning	1.0%		2.1%	1.0%	1.3%	9.8%	
City of Colton	1.0%		3.2%	1.0%	2.6%	14.7%	4.2%
City of Burbank	4.4%	4.5%	16.0%	15.4%	11.5%		31.0%
City of Glendale	4.4%	2.3%		14.8%	11.1%	9.8%	16.5%
City of Cerritos							4.2%
City of Pasadena	4.4%	5.9%		13.8%	8.6%		6.1%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

The Authority has entered into power sales and transmission service agreements with the above project participants. Under the terms of the contracts, the participants are entitled to power output or transmission service, as applicable. The participants are obligated to make payments on a "take or pay" basis for their proportionate share of operating and maintenance expenses and debt service. The contracts cannot be terminated or amended in any manner which will impair or adversely affect the rights of the bondholders as long as any bonds issued by the specific project remain outstanding.

The contracts expire as follows:

Palo Verde Project	2030
Southern Transmission System Project	2027
Hoover Uprating Project	2018
Mead-Phoenix Project	2030
Mead-Adelanto Project	2030
San Juan Project	2030
Magnolia Power Project	2036

Critical Accounting Policies

Method of Accounting – The accounting records of the Authority are maintained in accordance with accounting principles generally accepted in the United States of America. As a government-owned utility, in prior years the Authority applied all statements issued by the Governmental Accounting Standards Board (GASB) and all statements and interpretations issued by the Financial Accounting Standards Board (FASB) which were not in conflict with statements issued by the GASB. Effective July 1, 2002, the Authority changed its election under the guidance in GASB Statement No. 20, *Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities that Use Proprietary Fund Accounting,* to follow all GASB statements and only FASB statements and interpretations issued before November 30, 1989. See Note 2 to the financial statements discussing the results of this change in accounting principle.

Costs Recoverable – The Authority's billing amounts to the participants are determined by it's Board of Directors and are subject to review and approval by the participants. Billings to participants are designed to recover "costs" as defined by the power sales and transmission service agreements. The billings are structured to systematically provide for debt service requirements, operating funds and reserves in accordance with these agreements. The difference between billings and the Authority's expenses calculated in accordance with generally accepted accounting principles are deferred as costs recoverable in future periods and are presented as net assets. It is intended that the deferred amounts will be recovered through billings for repayment of principal on the related bonds.

Investment Policy and Controls – The Authority's investment function operates within a legal framework established by Sections 6509.5 and 53600 et. seq. of the California Government Code, Indentures of Trust, instruments governing financial arrangements entered into by the Authority to finance and operate Projects, and the Authority's Investment Policy. The Indentures of Trust authorize the establishment of specific Project funds and accounts, specify how monies are to be applied, and name third party Trustees.

Funds available for investment include proceeds from bonds and notes sales, payments from the participants, maturities of previous investments, earnings, exchanges of securities and interest from swap agreements. Funds are managed and invested on a separate accounting basis and principal and earnings are credited and allocated to designated funds or accounts as outlined in each Project's Indenture of Trust, or in the Projects' Stabilization Fund which was established by a Board Resolution.

The three fundamental criteria in the investment program, ranked in accordance of importance, are: safety of principal, liquidity and return. An exception to the preceding criteria is made for the Palo Verde Nuclear Decommissioning Trust Funds, as liquidity will not be a factor until 2023. The investment criteria for the Decommissioning Trust Funds, in order of importance, is as follows: safety of principal, return and liquidity.

Debt Management Program – The Authority's financing goal is to obtain the lowest prudent rates of interest on debt issues and to issue debt in the most cost-effective manner. In addition, the Authority will continue to utilize debt management strategies that reduce the overall cost of borrowing for its members. In general, the Authority issues new money debt and refunding debt on either a negotiated or competitive basis as determined by the Board. A minimum net present value savings of 5%, as a percent of the refunded par amount, is the general target when determining the potential to refund existing Authority debt. The Authority may also use interest rate swaps or other derivative products to help meet important financial objectives.

Using This Financial Report

This annual financial report consists of a series of financial statements and reflects the self-supporting activities of the Authority that are funded primarily through the sale of energy and transmission services to member agencies under project specific "take or pay" contracts that require each member agency to pay its proportionate share of operating and maintenance expenses and debt service with respect to such projects.

Combined Statements of Net Assets (Deficit), Combined Statements of Revenues, Expenses and Changes in Net Assets (Deficit), and Combined Statements of Cash Flows

The Combined Financial Statements provide an indication of the Authority's financial health. The Combined Statements of Net Assets (Deficit) include all of the Authority's assets and liabilities, using an accrual basis of accounting, as well as an indication about which assets can be utilized for general purposes and which assets are restricted as a result of bond covenants and other commitments. The Combined Statements of Revenues, Expenses and Changes in Net Assets (Deficit) report all of the revenues and expenses during the time periods indicated. The Combined Statements of Cash Flows report the cash provided and used by operating activities, as well as other cash sources such as investment income, cash payments for bond principal payments, and capital additions and betterments.

Palo Verde Project
Financial Highlights
(In thousands)

	June 30	
	2003	2002 (As restated)
Assets		
Utility plant, net	$ 183,818	$ 213,923
Investments	674,924	542,513
Cash and cash equivalents	105,142	60,149
Other	14,658	14,532
	$ 978,542	$ 831,117
Liabilities and Net Assets		
Long-term debt	$ 609,150	$ 629,554
Current liabilities	114,030	102,024
	723,180	731,578
Net assets (deficit):		
Invested in capital assets, net of related debt	(469,233)	(459,192)
Restricted net assets	706,613	536,840
Unrestricted net assets	17,982	21,891
Total net assets	255,362	99,539
	$ 978,542	$ 831,117
Revenues, Expenses and Changes in Net Assets		
Operating revenues	$ 180,529	$ 175,374
Operating expenses	(73,650)	(71,266)
Net operating income	106,879	104,108
Investment income	96,885	43,301
Debt expenses	(47,941)	(53,867)
Increase in net assets	155,823	93,542
Beginning balance of net assets	99,539	5,997
Ending balance of net assets	$ 255,362	$ 99,539

Net Assets – The Palo Verde Project's Net Assets increased by $155.8 million, mainly due to a $147.4 million increase in Assets and a decrease in Liabilities of $8.4 million. The increase in the Assets of the Project is primarily due to Participant contributions to the Deposit Installment Escrow Fund under a debt-restructuring plan adopted by the Board through a resolution in 1998 to increase the competitiveness of the Palo Verde Project by accelerating the repayment of the Project's debt. Under the debt-restructuring plan, an additional $65 million per year will be added to the Palo Verde Project Participants' billings through June 30, 2004. (Refer to Revenues in Note 2 of the Notes to Combined Financial Statements). During the year, the Authority restructured the 1997 B Escrow Restructuring Account, which resulted in a gain of $16.7 million after expenses, which was deferred and is being amortized over the life of the related bonds (see Note 5 of the Notes to Combined Financial Statements).

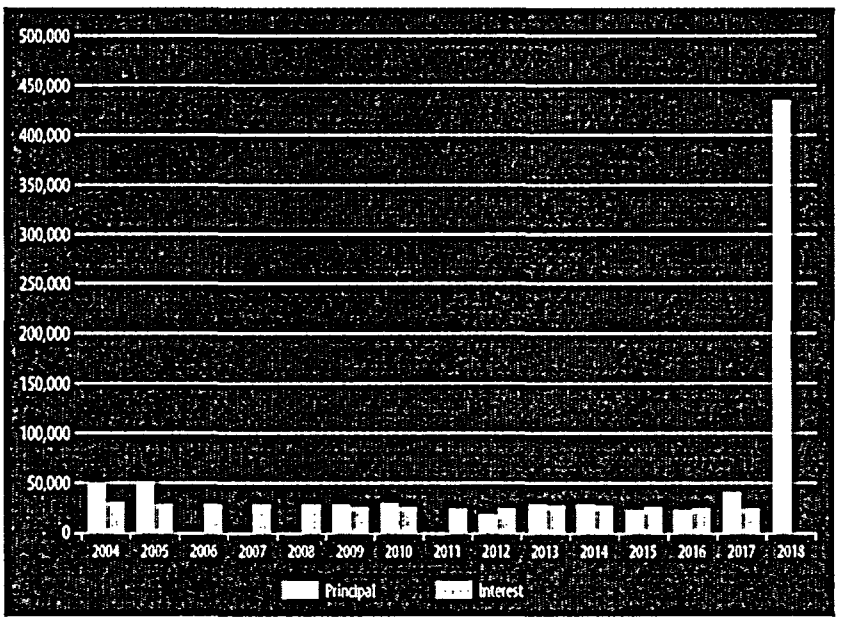
The decrease in Liabilities is primarily due to a decrease in long term debt of $20.4 million as a result of principal bond maturities and the amortization of the bond discounts, premiums and losses on refunding on the related debt, offset by the deferral of the $16.7 million gain on restructuring of the Escrow accounts.

Investment Income – The increase in the PV investment income of $53.6 million is primarily due to the unrealized gain recorded from the increases in the market value of Escrow accounts as a result of the downward movement of interest rates during the current fiscal year.

Long-term Debt – The Authority financed the acquisition of the assets of the Palo Verde Project through the issuance of revenue bonds. Currently, capital additions to the Project are financed from revenues received from participants.

The following graph provides an indication of the principal and interest payments on the Palo Verde Project that are due each year following June 30, 2003 until the bonds mature in 2018. Interest is reflected on an accrual basis.

Palo Verde Project
Debt Service Requirements
Fiscal Year Ending June 30
($ in thousands)



Interest payments on the bonds are payable semi-annually on July 1 and January 1 of each year.

Southern Transmission System Project (STS)
Financial Highlights
(In thousands)

	June 30 2003	June 30 2002 (As restated)
Assets		
Utility plant, net	$ 361,785	$ 381,414
Investments	58,802	83,474
Cash and cash equivalents	37,936	33,532
Other	23,001	20,603
	$ 481,524	$ 519,023
Liabilities and Net Deficit		
Long-term debt	$ 807,669	$ 830,680
Current liabilities	40,229	44,568
	847,898	875,248
Net assets (deficit):		
Invested in capital assets, net of related debt	(466,659)	(467,080)
Restricted net assets	100,939	115,910
Unrestricted net deficit	(654)	(5,055)
Total net deficit	(366,374)	(356,225)
	$ 481,524	$ 519,023
Revenues, Expenses and Changes in Net Deficit		
Operating revenues	$ 82,229	$ 77,573
Operating expenses	(33,433)	(36,864)
Net operating income	48,796	40,709
Investment income	6,131	4,961
Debt expenses	(62,592)	(62,458)
Extraordinary loss on debt refunding	(2,484)	(1,538)
Increase in net deficit	(10,149)	(18,326)
Beginning balance of net deficit	(356,225)	(337,899)
Ending balance of net deficit	$ (366,374)	$ (356,225)

Net Deficit – The Net Deficit of STS increased in 2003 by $10.1 million due to a $37.5 million decrease in Total Assets and a decrease in Liabilities of $27.4 million. The decrease in Total Assets consists mainly of:

- an increase in accumulated depreciation of $19.6 million,
- a decrease in investments of $24.7 million, and
- a $6.8 million increase in Current Assets.

The increase in accumulated depreciation was due to scheduled depreciation. The decrease of $24.7 million in Investments is primarily due to the release of $15.0 million and $2.1 million from the Debt Service accounts and General Reserve Fund, respectively, to fund a portion of the related refunded bonds (See Note 5 of the Notes to Combined Financial Statements).

The decrease in Liabilities of $27.4 million is due to the following:

- a decrease of $23.0 million in long-term debt due to maturities and refundings, and
- a decrease of $4.4 million in Current liabilities.

The Net Deficit of $366.4 million at June 30, 2003 consists of non-cash expenses which are not billed to the participants but are required to be recorded as expenses under generally accepted accounting principles. These non-cash expenses are primarily comprised of depreciation on utility plant, amortization of debt related expenses, amortization of bond premiums and discounts, and losses on refundings. These costs will be recovered at the time the Authority collects revenues to pay the principal portion of debt service costs.

Operating Income – The increase in STS operating income of $8.1 million is largely due to billings to Participants in excess of period costs and lower operating expenses. The primary reason for the higher billings in the current year is increased debt service requirements.

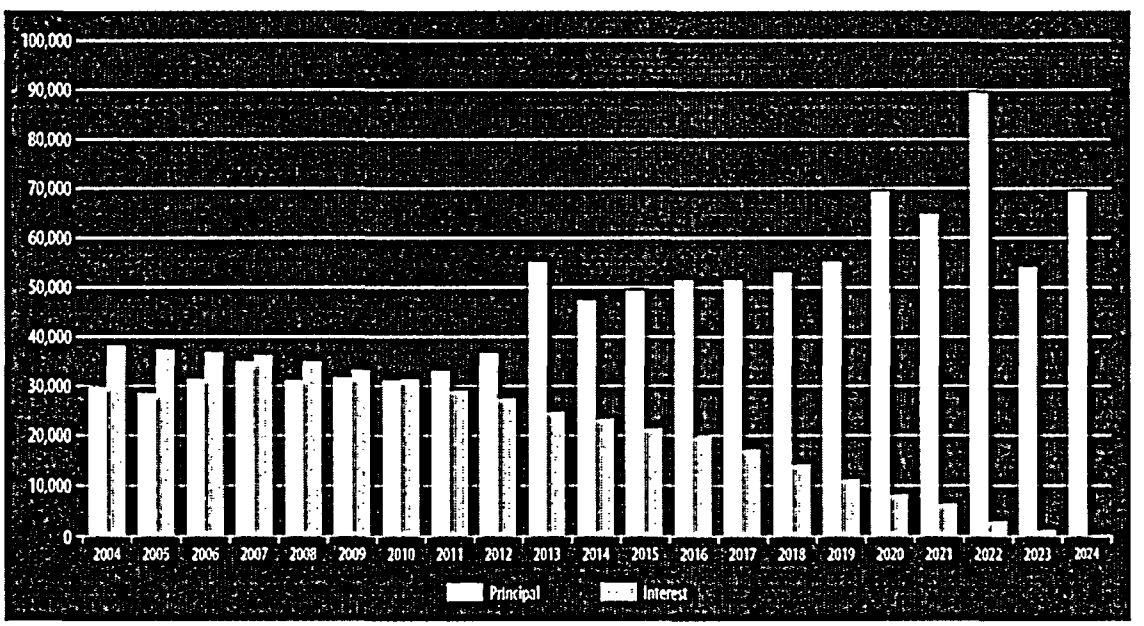
Long-term Debt – The Authority acquired the STS assets through the issuance of revenue bonds. Capital additions are currently financed with revenues received from participants. Principal bond maturities redeemed on July 1, 2002 totaled $26.7 million. During the year the Authority issued new refunding bonds as follows:

Description of Bonds	Par Amount of Refunded Bonds	Par Amount of Refunding Issue	Debt Service Savings	Present Value Savings	Bond Ratings by Moody's
Transmission Project Revenue Bonds 2002 Subordinate Refunding Series B	$ 46,400,000	$ 38,755,000	$ 8,697,986	$ 5,675,172	A1
Transmission Project Revenue Bonds 2003 Subordinate Refunding Series A	$ 58,495,000	$ 51,750,000	$ 13,257,524	$ 6,937,640	A1

As of June 30, 2003, Moody's increased the ratings on the STS 2002 and 2003 Subordinate Refunding Bonds to Aaa.

The following graph provides an indication of the principal and interest payments on the STS Project that are due each year following June 30, 2003 until the bonds mature in 2024. Interest is reflected on an accrual basis.

Southern Transmission System Project
Debt Service Requirements
Fiscal Year Ending June 30
($ in thousands)



Interest payments on the bonds are payable semi-annually on July 1 and January 1 of each year.

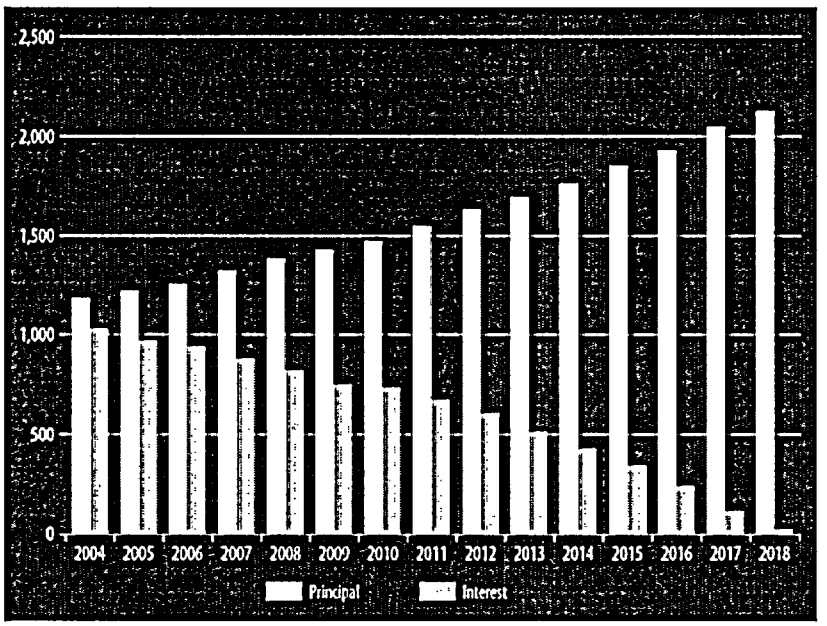
Hoover Uprating Project
Financial Highlights
(In thousands)

	June 30 2003	June 30 2002 (As restated)
Assets		
Utility plant, net	$ –	$ 4
Investments	500	3,972
Cash and cash equivalents	3,726	127
Other	20,674	21,757
	$ 24,900	$ 25,860
Liabilities and Net Assets		
Long-term debt	$ 19,404	$ 20,275
Current liabilities	1,643	1,423
	21,047	21,698
Net assets:		
Invested in capital assets, net of related debt	–	4
Restricted net assets	2,699	3,187
Unrestricted net assets	1,154	971
Total net assets	3,853	4,162
	$ 24,900	$ 25,860
Revenues, Expenses and Changes in Net Assets		
Operating revenues	$ 2,330	$ 2,352
Operating expenses	(2,381)	(2,236)
Net operating income	(51)	116
Investment income	73	187
Debt expenses	(331)	(840)
Extraordinary loss on debt refunding	–	(735)
Decrease in net assets	(309)	(1,272)
Beginning balance of net assets	4,162	5,434
Ending balance of net assets	$ 3,853	$ 4,162

Net Assets – The Net Assets of the Hoover Uprating Project decreased by $309,000. The net decrease is primarily due to a decrease in the Advances for capacity and energy balance. This balance consists of $20.2 million in advances provided by the Participants to the Hoover Power Plant, net of credits provided by the plant manager. In accordance with the agreements, these advances are returned through an annual amount of energy and capacity credits billed by the plant. Annual billings decrease the Advances for capacity and energy balance, up to the amount of principal paid on debt by the Authority. Credits in excess of principal paid on debt decrease the Project's current year interest expense. During the current year, the project billed $2.124 million, of which $970,000 was used to decrease the Advances balance. The remaining credits were utilized to offset debt expense.

Long-term Debt – The Authority acquired its interest in the Hoover Uprating Project through the issuance of revenue bonds. The following graph provides an indication of the principal and interest payments on the Hoover Uprating Project that are due each year following June 30, 2003 until the bonds mature in 2018. Interest is reflected on an accrual basis.

Hoover Uprating Project
Debt Service Requirements
Fiscal Year Ending June 30
($ in thousands)



Interest payments on the bonds are payable semi-annually on October 1 and April 1 of each year. Principal maturities of $905,000 were paid on October 1, 2002.

Mead-Phoenix Project
Financial Highlights
(In thousands)

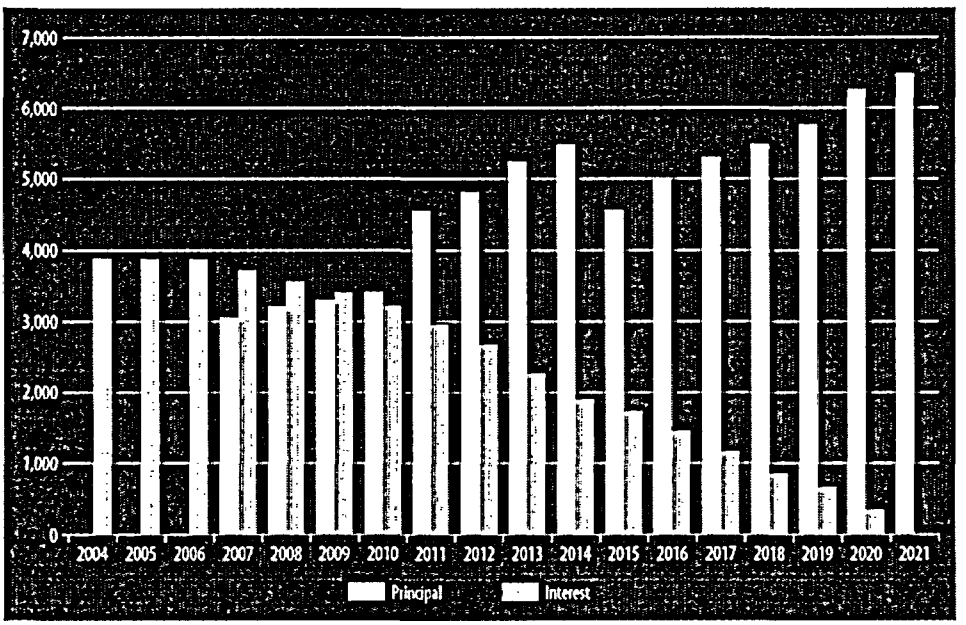
	June 30 2003	June 30 2002 (As restated)
Assets		
Utility plant, net	$ 42,786	$ 44,191
Investments	9,751	9,209
Cash and cash equivalents	1,617	2,081
Other	4,957	4,665
	$ 59,111	$ 60,146
Liabilities and Net Deficit		
Long-term debt	$ 64,224	$ 63,720
Current liabilities	2,841	3,274
	67,065	66,994
Net assets (deficit):		
Invested in capital assets, net of related debt	(20,672)	(18,686)
Restricted net assets	13,495	12,986
Unrestricted net deficit	(777)	(1,148)
Total net deficit	(7,954)	(6,848)
	$ 59,111	$ 60,146
Revenues, Expenses and Changes in Net Deficit		
Operating revenues	$ 3,987	$ 4,251
Operating expenses	(1,557)	(2,840)
Net operating income	2,430	1,411
Investment income	700	707
Debt expenses	(4,236)	(4,362)
Increase in net deficit	(1,106)	(2,244)
Beginning balance of net deficit	(6,848)	(4,604)
Ending balance of net deficit	$ (7,954)	$ (6,848)

Net Deficit – Net Deficit of the Mead-Phoenix Project increased by $1.1 million mainly due to an increase in accumulated depreciation on utility plant of $1.4 million.

Long-term Debt – The acquisition of the assets of the Mead-Phoenix Project was provided by a transfer of funds from the Multiple Project Fund (See Note 1 of the Notes to Combined Financial Statements). In March 1994, the Authority issued Mead-Phoenix Project Revenue Bonds to advance refund the Multiple Project Fund Bonds.

The following graph provides an indication of the principal and interest payments on the Mead-Phoenix Project that are due each year following June 30, 2003 until the bonds mature in 2021. Interest is reflected on an accrual basis.

Mead-Phoenix Project
Debt Service Requirements
Fiscal Year Ending June 30
($ in thousands)



Interest payments on the bonds are payable semi-annually on July 1 and January 1 of each year.

Mead-Adelanto Project
Financial Highlights
(In thousands)

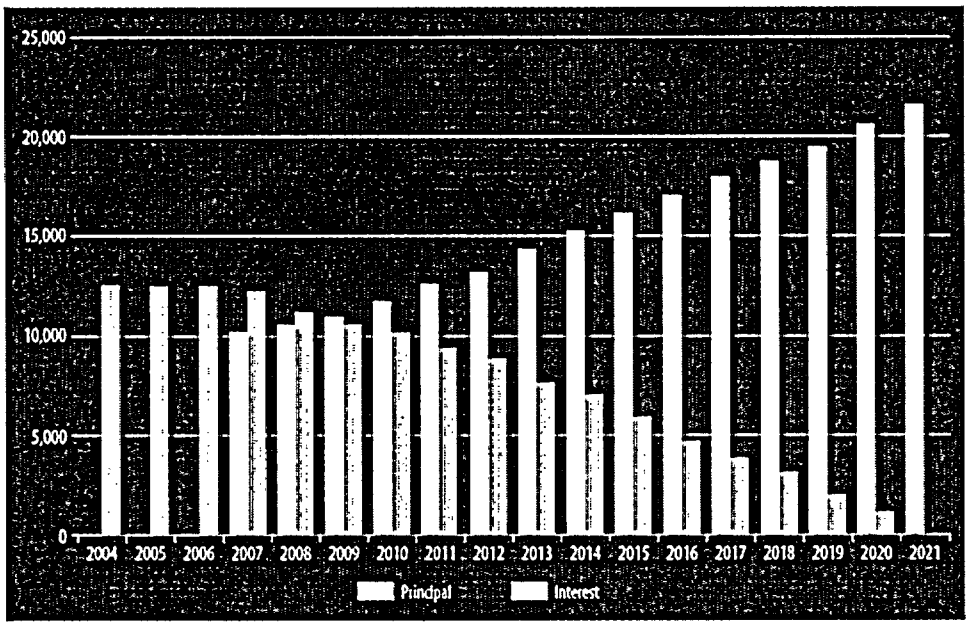
	June 30 2003	June 30 2002 (As restated)
Assets		
Utility plant, net	$ 140,031	$ 144,532
Investments	27,471	26,461
Cash and cash equivalents	2,791	3,894
Other	14,236	13,453
	$ 184,529	$ 188,340
Liabilities and Net Deficit		
Long-term debt	$ 207,307	$ 205,678
Current liabilities	7,338	8,043
	214,645	213,721
Net assets (deficit):		
Invested in capital assets, net of related debt	(64,540)	(58,184)
Restricted net assets	35,469	34,329
Unrestricted net deficit	(1,045)	(1,526)
Total net deficit	(30,116)	(25,381)
	$ 184,529	$ 188,340
Revenues, Expenses and Changes in Net Deficit		
Operating revenues	$ 11,792	$ 11,593
Operating expenses	(4,955)	(5,778)
Net operating income	6,837	5,815
Investment income	1,860	1,915
Debt expenses	(13,432)	(13,476)
Increase in net deficit	(4,735)	(5,746)
Beginning balance of net deficit	(25,381)	(19,635)
Ending balance of net deficit	$ (30,116)	$ (25,381)

Net Deficit – The Net Deficit of the Mead-Adelanto Project increased by $4.7 million largely due to an increase in accumulated depreciation on utility plant of $4.5 million.

Long-term Debt – Similar to the Mead-Phoenix Project, the interest in the Mead-Adelanto Project was acquired by the Authority through a transfer of funds, and the bonds issued to obtain these funds, from the Multiple Project Fund (See Note 1 of the Notes to Combined Financial Statements). In March 1994, the Authority issued Mead-Adelanto Project Revenue Bonds to advance refund the Multiple Project Fund Bonds.

The following graph provides an indication of the principal and interest payments on the Mead-Adelanto Project that are due each year following June 30, 2003 until the bonds mature in 2021. Interest is reflected on an accrual basis.

Mead-Adelanto Project
Debt Service Requirements
Fiscal Year Ending June 30
($ in thousands)



Interest payments on the bonds are payable semi-annually on July 1 and January 1 of each year.

Multiple Project Fund
Financial Highlights
(In thousands)

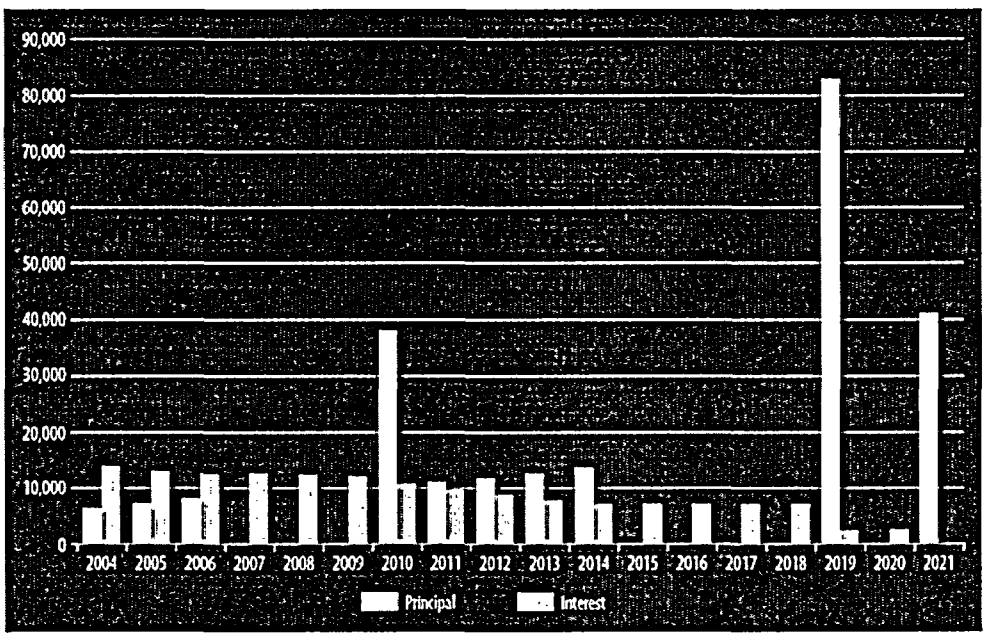
	June 30 2003	June 30 2002 (As restated)
Assets		
Investments	$ 243,437	$ 247,584
Cash and cash equivalents	–	1
Other	8,673	8,960
	$ 252,110	$ 256,545
Liabilities and Net Assets		
Long-term debt	$ 216,445	$ 222,865
Current liabilities	28,973	27,325
	245,418	250,190
Net assets:		
Invested in capital assets, net of related debt	–	–
Restricted net assets	6,692	6,355
Unrestricted net assets	–	–
Total net assets	6,692	6,355
	$ 252,110	$ 256,545
Revenues, Expenses and Changes in Net Assets		
Investment income	$ 17,275	$ 18,036
Debt expenses	(16,938)	(17,242)
Increase (decrease) in net assets	337	794
Beginning balance of net assets	6,355	5,561
Ending balance of net assets	$ 6,692	$ 6,355

Net Assets – There was no significant change in the Net Assets of the Multiple Project Fund for the year. The increase of $337,000 represents the difference between investment income earned on bond proceeds deposited in the Multiple Project Fund and the interest expense on such bonds.

Long-term Debt – The Multiple Project Fund was established by the issuance of revenue bonds. The bond proceeds are to be used to finance costs of construction and acquisition of ownership interests or capacity rights in one or more projects that the Authority expects to undertake. Certain of these funds were used to finance the Authority's interest in the Mead-Phoenix and Mead-Adelanto Projects (See Note 1 of the Notes to Combined Financial Statements).

The following graph provides an indication of the principal and interest payments on the Multiple Project Fund that are due each year following June 30, 2003 until the bonds mature in 2021. Interest is reflected on an accrual basis.

Multiple Project Fund
Debt Service Requirements
Fiscal Year Ending June 30
($ in thousands)



Interest payments on the bonds are payable semi-annually on July 1 and January 1 of each year. Par value of bonds that matured and were redeemed on July 1, 2002 was $6.6 million. A total of $125.5 million of the outstanding Multiple Project Revenue Bonds are not subject to redemption prior to maturity.

San Juan Project
Financial Highlights
(In thousands)

	June 30	
	2003	2002 (As restated)
Assets		
Utility plant, net	$ 80,989	$ 93,851
Investments	21,602	16,052
Cash and cash equivalents	15,930	15,063
Other	14,859	6,143
	$ 133,380	$ 131,109
Liabilities and Net Deficit		
Long-term debt	$ 200,699	$ 200,675
Current liabilities	16,980	19,030
	217,679	219,705
Net assets (deficit):		
Invested in capital assets, net of related debt	(125,669)	(105,828)
Restricted net assets	27,548	14,601
Unrestricted net assets	13,822	2,631
Total net deficit	(84,299)	(88,596)
	$ 133,380	$ 131,109
Revenues, Expenses and Changes in Net Deficit		
Operating revenues	$ 70,636	$ 50,258
Operating expenses	(56,783)	(56,195)
Net operating income (loss)	13,853	(5,937)
Investment income	1,289	724
Debt expenses	(10,771)	(11,013)
Extraordinary loss on debt refunding	(74)	(274)
Decrease (increase) in net deficit	4,297	(16,500)
Beginning balance of net deficit	(88,596)	(72,096)
Ending balance of net deficit	$ (84,299)	$ (88,596)

Net Deficit – The Net Deficit of the San Juan Project decreased by $4.3 million, primarily due to an increase of $2.3 million in Total Assets and a decrease in Total Liabilities of $2.0 million. The increase in Total Assets of $2.3 million is largely due to an increase in investments of $5.6 million, due mainly to the new Debt Service Reserve Account that was created when the 2002 Refunding Series B Bonds were issued in October 2002. In addition, Current Assets increased by $9.7 million largely due to the recognition of a receivable from Participants to fund actual costs for the current year. These increases were offset by a $12.9 million decrease in Utility Plant due to scheduled depreciation.

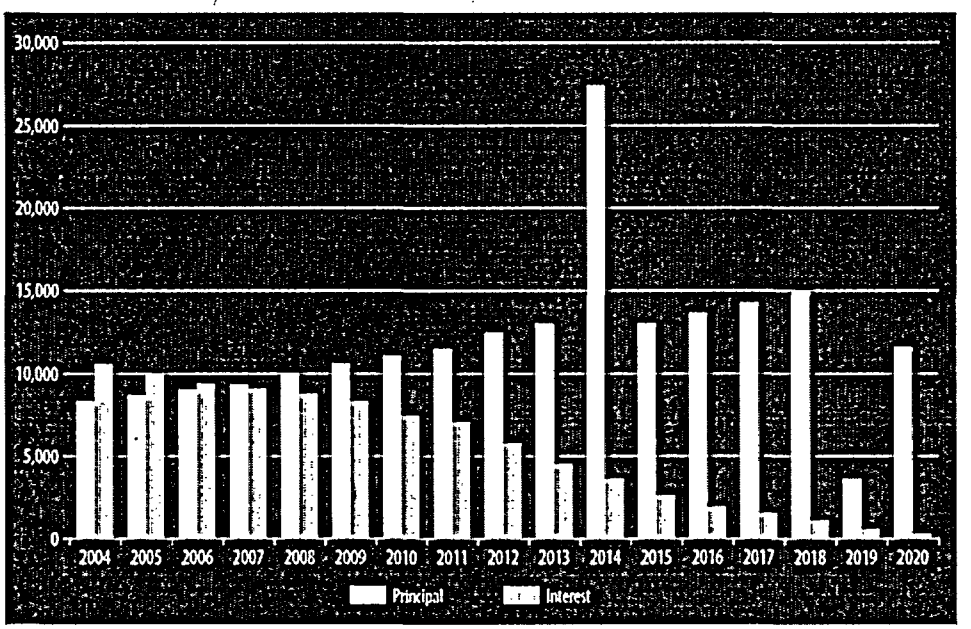
Net Operating Income (Loss) – Net Operating Income increased by $19.8 million when compared to last year. This increase is primarily due to the $8.9 million reduced billings to Participants during the 2002 fiscal year as a result of applying the $8.9 million transfer amount from the Debt Service Reserve Fund to the 2002 fiscal year billings. No such transfers from the Debt Service Reserve Fund were made to reduce current year billings. Also included in current year's revenues is the $9.9 million billing for the Coal Contract Buyout made in December 2002 (See Note 2 of the Notes to Combined Financial Statements).

Long-term Debt – The Authority financed its acquisition of the assets of the San Juan Project by the issuance of revenue bonds. Currently, capital additions are financed from revenues received from participants. Principal bond maturities that were redeemed on January 1, 2003 totaled $1.6 million. During the year, the Authority issued new refunding bonds as follows:

Description of Bonds	Par Amount of Refunded Bonds	Par Amount of Refunding Issue	Debt Service Savings	Present Value Savings	Bond Ratings by Moody's
San Juan Power Project Bonds, 2002 Refunding Series B	$ 70,800,000	$ 71,850,000	$ 12,932,905	$ 8,131,998	A2

The graph below provides an indication of the principal and interest payments on the San Juan Project that are due each year following June 30, 2003 until the bonds mature in 2020. Interest is reflected on an accrual basis.

San Juan Project
Debt Service Requirements
Fiscal Year Ending June 30
($ in thousands)



Interest payment on the bonds are payable semi-annually on July 1 and January 1 of each year.

Magnolia Power Project ("The Project")

Background – In 2000, the City of Burbank (the "City"), an Authority member, began exploring ways to replace an aging power plant within the city limits and decided that it would be more economical to build a plant with more capacity than required to meet its power demands. To build the plant, the City needed other participants to buy the excess power and it presented the idea to the Authority. Four members, the Cities of Anaheim, Colton, Glendale, and Pasadena (the "Project A Participants"), indicated their interest in joining the City of Burbank in the Project. The City of Cerritos (the "Project B Participant"), who became a member of the Authority in July 2001, also decided to participate in the Project.

In March 2003, the California Energy Commission gave its approval for construction of the Magnolia Power Project. The Project is a natural gas-fired generator and is designed to generate 242 megawatts to meet baseload capacity but will be able to generate more than 300 megawatts for short periods of time during peak demand periods. The plant is the first to be owned by the Authority, and the City of Burbank will manage its construction and operation. To finance the Project, the Authority issued $299.975 million of Magnolia Power Project A, Revenue Bonds, 2003-1 and $14.105 million of Magnolia Power Project B, Lease Revenue Bonds (City of Cerritos, California) 2003-1 in April 2003 (Refer to Note 5 of the Notes to Combined Financial Statements).

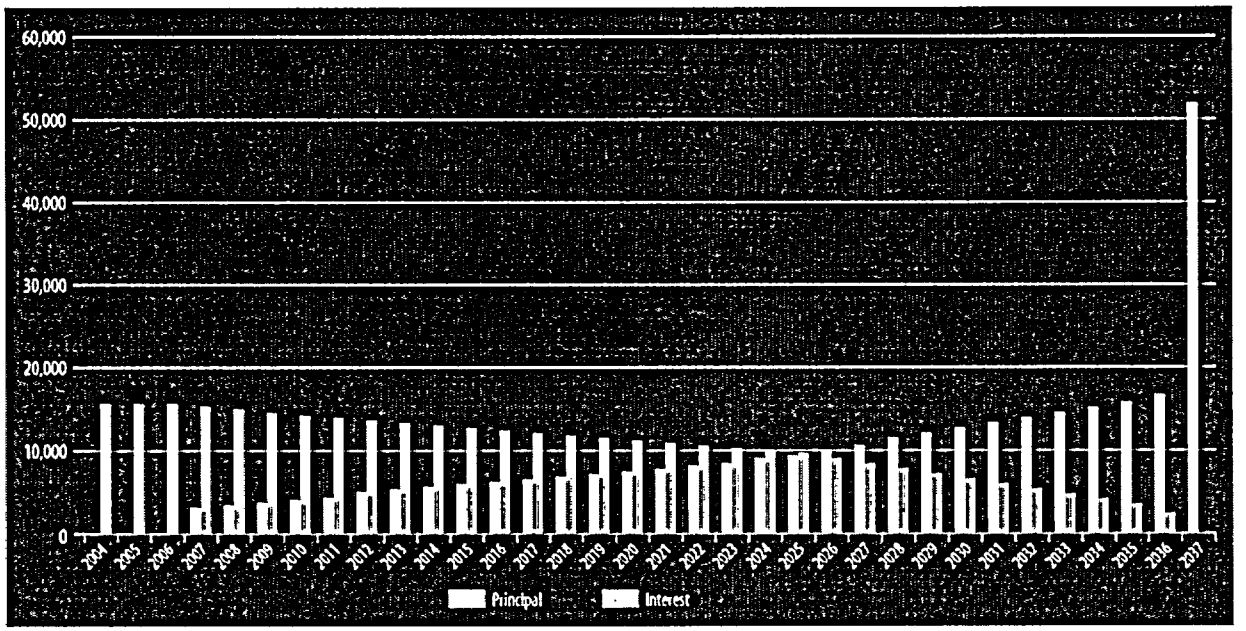
The following table summarizes the financial position of the Project as of June 30, 2003. Amounts are in thousands.

	June 30 2003
Assets	
Utility plant, net	$ 93,610
Investments	70,426
Cash and cash equivalents	162,381
Other	7,234
	$ 333,651
Liabilities and Net Assets	
Long-term debt	$ 321,730
Current liabilities	11,921
	333,651
Net assets:	
Invested in capital assets, net of related debt	–
Restricted net assets	–
Unrestricted net assets	–
Total net assets	$ –

During the current year, the Project had no revenues and is not anticipated to have any until the Project becomes operational. Costs related to the construction of the plant of $91.6 million and debt service costs of $3.7 million offset by investment income of $1.7 million, were capitalized as part of the utility plant balance. Once the plant becomes operational, these costs will be recovered through future billings to participants.

The following graph provides an indication of the principal and interest payments on the Project that are due each year on July 1 until the bonds mature in 2036. Interest is reflected on an accrual basis.

Magnolia Power Project
Debt Service Requirements
Fiscal Year Ending June 30
($ in thousands)



Interest payments on the bonds are payable semi-annually on July 1 and January 1 of each year.

Projects' Stabilization Fund – In 1996 the Board adopted a resolution to establish the Projects' Stabilization Fund. Monies deposited by the participants to this Fund are used to pay for Authority costs as directed by the Participants (See Note 1 of the Notes to Combined Financial Statements). At June 30, 2003 the Fund had a balance of $96.4 million.

Financial Outlook – The Authority's credit strength is based on:

- The collective credit strengths of each project participant;
- The absence of concentration risk as evidenced by the lack of substantial reliance by one participant on the resources financed;
- The low cost power the Project provides the participants; and,
- Strong legal provisions.

The Authority has take-or-pay power sales and transmission service contracts which unconditionally require the Participants to pay for the cost of operating and maintaining the Projects, including debt service, whether or not the Projects are operating or operable. Although the contracts have not been court-tested, a municipal utility's authority to enter into such contracts is rooted in the State's constitutional provisions for municipal electric utilities.

The Authority continues to play an important role as a legislative advocate and its focused strategic plan continues to provide benefits to member agencies as they prepare for increased competition. The Authority's management has been very focused on lowering the fixed costs of each project to ensure the flexibility needed to perform in a more competitive marketplace. An example is the refunding of $175.7 million of the Authority's long-term debt during the fiscal year, which generated $34.9 million of debt service savings. In addition, in February 2003 the Authority restructured the Palo Verde 1993 Escrow Funds resulting in a net gain of $16.7 million, which was deferred and is being amortized over the remaining period of the related bonds.

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors and Participants of the
Southern California Public Power Authority:

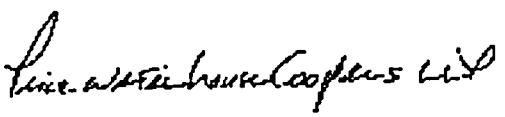
In our opinion, the accompanying combined statements of net assets (deficit) and the related combined statements of revenues, expenses and changes in net assets (deficit) and cash flows present fairly, in all material respects, the financial position of the Southern California Public Power Authority (the "Authority") at June 30, 2003 and 2002, and the changes in its net assets (deficit) and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Authority's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the accompanying combined statements of net assets (deficit) and the related combined statements of revenues, expenses and changes in net assets (deficit) and cash flows present fairly, in all material respects, the financial position of each of the Authority's Palo Verde Project, Southern Transmission System Project, Hoover Uprating Project, Mead-Phoenix Project, Mead-Adelanto Project, Multiple Project Fund, San Juan Project, and Projects' Stabilization Fund at June 30, 2003 and 2002, and the changes in their net assets (deficit) and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the accompanying combined statement of net assets and the related combined statement of revenues, expenses and changes in net assets and cash flows present fairly, in all material respects, the financial position of the Authority's Magnolia Power Project at June 30, 2003, and the changes in its net assets and its cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Authority's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 2 to the financial statements, effective July 1, 2002, the Authority changed its election under Governmental Accounting Standards Board Statement No. 20, *Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities that Use Proprietary Fund Accounting*, and no longer applies Financial Accounting Standards Board statements and interpretations issued after November 30, 1989. The Authority has restated all prior years presented to give effect of this change in election.

The management's discussion and analysis included on pages 20-38 is not a required part of the basic financial statements but is supplementary information required by the Governmental Accounting Standards Board. We have applied certain limited procedures, which consisted principally of inquiries of management regarding the methods of measurement and presentation of the supplementary information. However, we did not audit the information and express no opinion on it.

Our audits were conducted for the purpose of forming an opinion on the basic financial statements taken as a whole. The supplemental financial information, as listed in the accompanying index, is presented for purposes of additional analysis and is not a required part of the basic financial statements. Such information has been subjected to the auditing procedures applied in the audit of the basic financial statements and, in our opinion, is fairly stated in all material respects in relation to the basic financial statements taken as a whole.



September 8, 2003

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED STATEMENTS OF NET ASSETS (DEFICIT)
JUNE 30, 2003
(Amounts in thousands)

	June 30, 2003									
	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead-Phoenix Project	Mead-Adelanto Project	Multiple Project Fund	San Juan Project	Magnolia Power Project	Projects' Stabilization Fund	Total
ASSETS										
Noncurrent Assets										
Utility plant:										
Production	$ 623,352	$ –	$ –	$ –	$ –	$ –	$ 172,475	$ –	$ –	$ 795,827
Transmission	14,062	674,606	–	50,770	172,319	–	–	–	–	911,757
General	2,705	18,911	22	2,640	473	–	8,067	–	–	32,818
	640,119	693,517	22	53,410	172,792	–	180,542	–	–	1,740,402
Less - Accumulated depreciation	489,707	331,732	22	10,624	32,761	–	99,826	–	–	964,672
	150,412	361,785	–	42,786	140,031	–	80,716	–	–	775,730
Construction work in progress	18,862	–	–	–	–	–	273	93,610	–	112,745
Nuclear fuel, at amortized cost	14,544	–	–	–	–	–	–	–	–	14,544
Net utility plant	183,818	361,785	–	42,786	140,031	–	80,989	93,610	–	903,019
Special funds:										
Restricted investments										
Escrow accounts	420,766	16,883	–	–	–	–	–	–	–	437,649
Decommissioning fund	116,936	–	–	–	–	–	–	–	–	116,936
Other funds	124,227	41,919	–	9,751	27,471	243,437	21,602	70,426	53,044	591,877
	661,929	58,802	–	9,751	27,471	243,437	21,602	70,426	53,044	1,146,462
Unrestricted Investments										
Other funds	12,995	–	500	–	–	–	–	–	–	13,495
Total special funds	674,924	58,802	500	9,751	27,471	243,437	21,602	70,426	53,044	1,159,957
Other Noncurrent Assets										
Advance to IPA - restricted	–	11,550	–	–	–	–	–	–	–	11,550
Advances for capacity and energy, net - restricted	–	–	20,197	–	–	–	–	–	–	20,197
Unamortized debt expenses	5,382	8,945	476	766	2,736	–	2,590	6,100	–	26,995
Total other noncurrent assets	5,382	20,495	20,673	766	2,736	–	2,590	6,100	–	58,742
Total noncurrent assets	864,124	441,082	21,173	53,303	170,238	243,437	105,181	170,136	53,044	2,121,718
Current Assets										
Special funds:										
Cash and cash equivalents - restricted	96,075	37,372	2,884	1,498	2,616	–	11,236	162,381	42,941	357,003
Cash and cash equivalents - unrestricted	9,067	564	842	119	175	–	4,694	–	–	15,461
Interest receivable	1,405	137	1	343	915	8,673	13	1,061	436	12,984
Accounts receivable	1,043	2,369	–	–	3	–	9,021	73	–	12,509
Due from other project - restricted	–	–	–	3,848	10,582	–	–	–	–	14,430
Materials and supplies	6,828	–	–	–	–	–	3,235	–	–	10,063
Total current assets	114,418	40,442	3,727	5,808	14,291	8,673	28,199	163,515	43,377	422,450
Total assets	978,542	481,524	24,900	59,111	184,529	252,110	133,380	333,651	96,421	2,544,168
LIABILITIES										
Noncurrent liabilities										
Long-term debt	609,150	807,669	19,404	64,224	207,307	216,445	200,699	321,730	–	2,446,628
Commitments and contingencies (Note 7)	–	–	–	–	–	–	–	–	–	–
Total noncurrent liabilities	609,150	807,669	19,404	64,224	207,307	216,445	200,699	321,730	–	2,446,628
Current liabilities:										
Debt due within one year	49,190	29,720	1,190	–	–	7,100	8,390	–	–	95,590
Accrued interest	7,197	6,922	265	1,945	6,116	7,443	5,303	4,467	–	39,658
Accounts payable and accruals	56,095	3,587	188	896	1,222	–	2,887	7,454	–	72,329
Accrued property tax	1,548	–	–	–	–	–	400	–	–	1,948
Coal contracts buyout	–	–	–	–	–	–	–	–	–	–
Due to other projects	–	–	–	–	–	14,430	–	–	–	14,430
Total current liabilities	114,030	40,229	1,643	2,841	7,338	28,973	16,980	11,921	–	223,955
Total liabilities	723,180	847,898	21,047	67,065	214,645	245,418	217,679	333,651	–	2,670,583
NET ASSETS (DEFICIT)										
Invested in capital assets, net of related debt and deferred credits	(469,233)	(466,659)	–	(20,672)	(64,540)	–	(125,669)	–	–	(1,146,773)
Restricted net assets	706,613	100,939	2,699	13,495	35,469	6,692	27,548	–	96,421	989,876
Unrestricted net assets (deficit)	17,982	(654)	1,154	(777)	(1,045)	–	13,822	–	–	30,482
Total net assets (deficit)	$ 255,362	$ (366,374)	$ 3,853	$ (7,954)	$ (30,116)	$ 6,692	$ (84,299)	$ –	$ 96,421	$ (126,415)

The accompanying notes are an integral part of the combined financial statements.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED STATEMENTS OF NET ASSETS (DEFICIT)
JUNE 30, 2002
(Amounts in thousands)

	June 30, 2002 (Restated)								
	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead-Phoenix Project	Mead-Adelanto Project	Multiple Project Fund	San Juan Project	Projects' Stabilization Fund	Total
ASSETS									
Noncurrent Assets									
Utility plant:									
Production	$ 620,719	$ –	$ –	$ –	$ –	$ –	$ 175,111	$ –	$ 795,830
Transmission	14,062	674,606	–	50,770	172,319	–	–	–	911,757
General	2,583	18,911	22	2,640	473	–	8,089	–	32,718
	637,364	693,517	22	53,410	172,792	–	183,200	–	1,740,305
Less - Accumulated depreciation	452,747	312,103	18	9,219	28,260	–	90,204	–	892,551
	184,617	381,414	4	44,191	144,532	–	92,996	–	847,754
Construction work in progress	14,325	–	–	–	–	–	855	–	15,180
Nuclear fuel, at amortized cost	14,981	–	–	–	–	–	–	–	14,981
Net utility plant	213,923	381,414	4	44,191	144,532	–	93,851	–	877,915
Special funds:									
Restricted Investments									
Escrow accounts	284,327	21,639	–	–	–	–	–	–	305,966
Decommissioning fund	104,671	–	–	–	–	–	–	–	104,671
Other funds	139,987	61,835	2,861	9,209	26,461	247,584	16,052	158,320	662,309
	528,985	83,474	2,861	9,209	26,461	247,584	16,052	158,320	1,072,946
Unrestricted Investments									
Other funds	13,528	–	1,111	–	–	–	–	–	14,639
Total special funds	542,513	83,474	3,972	9,209	26,461	247,584	16,052	158,320	1,087,585
Other Noncurrent Assets									
Advance to IPA - restricted	–	11,550	–	–	–	–	–	–	11,550
Advances for capacity and energy, net - restricted	–	–	21,169	–	–	–	–	–	21,169
Unamortized debt expenses	3,912	8,881	572	843	2,962	–	2,693	–	19,863
Total other noncurrent assets	3,912	20,431	21,741	843	2,962	–	2,693	–	52,582
Total noncurrent assets	760,348	485,319	25,717	54,243	173,955	247,584	112,596	158,320	2,018,082
Current Assets									
Special funds:									
Cash and cash equivalents - restricted	48,371	29,171	29	1,900	3,493	1	11,779	14,970	109,714
Cash and cash equivalents - unrestricted	11,778	4,361	98	181	401	–	3,284	–	20,103
Interest receivable	2,483	172	16	340	916	8,960	18	495	13,400
Accounts receivable	1,244	–	–	–	–	–	209	–	1,453
Due from other project - restricted	–	–	–	3,482	9,575	–	–	–	13,057
Materials and supplies	6,893	–	–	–	–	–	3,223	–	10,116
Total current assets	70,769	33,704	143	5,903	14,385	8,961	18,513	15,465	167,843
Total assets	831,117	519,023	25,860	60,146	188,340	256,545	131,109	173,785	2,185,925
LIABILITIES									
Noncurrent liabilities									
Long-term debt	629,554	830,680	20,275	63,720	205,678	222,865	200,675	–	2,173,447
Commitments and contingencies (Note 7)	–	–	–	–	–	–	–	–	–
Total other noncurrent liabilities	629,554	830,680	20,275	63,720	205,678	222,865	200,675	–	2,173,447
Current liabilities:									
Debt due within one year	47,395	26,695	905	–	–	6,600	1,600	–	83,195
Accrued interest	8,122	8,457	274	1,945	6,116	7,668	3,325	–	35,907
Accounts payable and accruals	44,557	9,416	244	550	963	–	3,732	–	59,462
Accrued property tax	1,950	–	–	779	964	–	450	–	4,143
Coal contracts buyout	–	–	–	–	–	–	9,923	–	9,923
Due to other projects	–	–	–	–	–	13,057	–	–	13,057
Total current liabilities	102,024	44,568	1,423	3,274	8,043	27,325	19,030	–	205,687
Total liabilities	731,578	875,248	21,698	66,994	213,721	250,190	219,705	–	2,379,134
NET ASSETS (DEFICIT)									
Invested in capital assets net of related debt and deferred credits	(459,192)	(467,080)	4	(18,686)	(58,184)	–	(105,828)	–	(1,108,966)
Restricted net assets	536,840	115,910	3,187	12,986	34,329	6,355	14,601	173,785	897,993
Unrestricted net assets (deficit)	21,891	(5,055)	971	(1,148)	(1,526)	–	2,631	–	17,764
Total net assets (deficit)	$ 99,539	$ (356,225)	$ 4,162	$ (6,848)	$ (25,381)	$ 6,355	$ (88,596)	$ 173,785	$ (193,209)

The accompanying notes are an integral part of the combined financial statements.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED STATEMENTS OF REVENUES, EXPENSES AND CHANGES IN NET ASSETS (DEFICIT)
FOR THE YEAR ENDED JUNE 30, 2003
(Amounts in thousands)

	Year Ended June 30, 2003									
	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead-Phoenix Project	Mead-Adelanto Project	Multiple Project Fund	San Juan Project	Magnolia Power Project	Projects' Stabilization Fund	Total
Operating revenues:										
Sales of electric energy	$ 180,529	$ –	$ 2,330	$ –	$ –	$ –	$ 70,636	$ –	$ –	$ 253,495
Sales of transmission services	–	82,229	–	3,987	11,792	–	–	–	–	98,008
Total operating revenues	180,529	82,229	2,330	3,987	11,792	–	70,636	–	–	351,503
Operating expenses:										
Operations and maintenance	27,462	13,804	2,377	152	454	–	43,586	–	–	87,835
Depreciation	26,702	19,629	4	1,405	4,501	–	10,084	–	–	62,325
Amortization of nuclear fuel	8,586	–	–	–	–	–	–	–	–	8,586
Decommissioning	10,900	–	–	–	–	–	3,113	–	–	14,013
Total operating expenses	73,650	33,433	2,381	1,557	4,955	–	56,783	–	–	172,759
Operating income (loss)	106,879	48,796	(51)	2,430	6,837	–	13,853	–	–	178,744
Non operating revenues (expenses)										
Investment income	96,885	6,131	73	700	1,860	17,275	1,289	–	2,372	126,585
Debt expense	(47,941)	(62,592)	(331)	(4,236)	(13,432)	(16,938)	(10,771)	–	–	(156,241)
Net non operating revenues (expenses)	48,944	(56,461)	(258)	(3,536)	(11,572)	337	(9,482)	–	2,372	(29,656)
Increase (decrease) in net assets (deficit) before extraordinary items	155,823	(7,665)	(309)	(1,106)	(4,735)	337	4,371	–	2,372	149,088
Extraordinary loss on refunding of debt	–	(2,484)	–	–	–	–	(74)	–	–	(2,558)
Net increase (decrease) in net assets (deficit)	155,823	(10,149)	(309)	(1,106)	(4,735)	337	4,297	–	2,372	146,530
Net assets (deficit) - beginning of year	99,539	(356,225)	4,162	(6,848)	(25,381)	6,355	(88,596)	–	173,785	(193,209)
Net withdrawals by participants	–	–	–	–	–	–	–	–	(79,736)	(79,736)
Net assets (deficit) - end of year	$ 255,362	$ (366,374)	$ 3,853	$ (7,954)	$ (30,116)	$ 6,692	$ (84,299)	$ –	$ 96,421	$ (126,415)

The accompanying notes are an integral part of the combined financial statements.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED STATEMENTS OF REVENUES, EXPENSES AND CHANGES IN NET ASSETS (DEFICIT)
FOR THE YEAR ENDED JUNE 30, 2002
(Amounts in thousands)

	Year Ended June 30, 2002 (Restated)								
	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead-Phoenix Project	Mead-Adelanto Project	Multiple Project Fund	San Juan Project	Projects' Stabilization Fund	Total
Operating revenues:									
Sales of electric energy	$ 175,374	$ –	$ 2,352	$ –	$ –	$ –	$ 50,258	$ –	$ 227,984
Sales of transmission services	–	77,573	–	4,251	11,593	–	–	–	93,417
Total operating revenues	175,374	77,573	2,352	4,251	11,593	–	50,258	–	321,401
Operating expenses:									
Operations and maintenance	24,434	17,231	2,232	1,434	1,276	–	43,010	–	89,617
Depreciation	26,701	19,633	4	1,406	4,502	–	10,072	–	62,318
Amortization of nuclear fuel	8,259	–	–	–	–	–	–	–	8,259
Decommissioning	11,872	–	–	–	–	–	3,113	–	14,985
Total operating expenses	71,266	36,864	2,236	2,840	5,778	–	56,195	–	175,179
Operating income (loss)	104,108	40,709	116	1,411	5,815	–	(5,937)	–	146,222
Non operating revenues (expenses):									
Investment income	43,301	4,961	187	707	1,915	18,036	724	10,561	80,392
Debt expense	(53,867)	(62,458)	(840)	(4,362)	(13,476)	(17,242)	(11,013)	–	(163,258)
Net non operating revenues (expenses)	(10,566)	(57,497)	(653)	(3,655)	(11,561)	794	(10,289)	10,561	(82,866)
Increase (decrease) in net assets (deficit) before extraordinary items	93,542	(16,788)	(537)	(2,244)	(5,746)	794	(16,226)	10,561	63,356
Extraordinary loss on refunding of debt	–	(1,538)	(735)	–	–	–	(274)	–	(2,547)
Net increase (decrease) in net assets (deficit)	93,542	(18,326)	(1,272)	(2,244)	(5,746)	794	(16,500)	10,561	60,809
Net assets (deficit) - beginning of year	5,997	(337,899)	5,434	(4,604)	(19,635)	5,561	(72,096)	200,350	(216,892)
Net withdrawals from participants	–	–	–	–	–	–	–	(37,126)	(37,126)
Net assets (deficit) - end of year	$ 99,539	$ (356,225)	$ 4,162	$ (6,848)	$ (25,381)	$ 6,355	$ (88,596)	$ 173,785	$ (193,209)

The accompanying notes are an integral part of the combined financial statements.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED STATEMENTS OF CASH FLOWS
FOR THE YEAR ENDED JUNE 30, 2003
(Amounts in thousands)

	Year Ended June 30, 2003									
	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead-Phoenix Project	Mead-Adelanto Project	Multiple Project Fund	San Juan Project	Magnolia Power Project	Projects' Stabilization Fund	Total
Cash flows from operating activities:										
Receipts from participants	$ 191,357	$ 72,665	$ 2,289	$ 4,179	$ 11,407	$ –	$ 61,123	$ –	$ –	$ 343,020
Payments to operating managers	(29,317)	(13,475)	(261)	(1,009)	(1,125)	–	(53,811)	–	–	(98,998)
Other receipts	166	3	3	100	4	–	–	–	–	276
Net cash flow from operating activities	162,206	59,193	2,031	3,270	10,286	–	7,312	–	–	244,298
Cash flows from noncapital financing activities:										
Withdrawals by participants, net	–	–	–	–	–	–	–	–	(79,736)	(79,736)
Cash flows from capital and related financing activities:										
Additions to plant, net	(15,996)	–	–	–	–	–	(290)	(84,119)	–	(100,405)
Debt interest payments	(35,192)	(42,149)	(1,077)	(3,889)	(12,232)	(15,111)	(7,485)	–	–	(117,135)
Proceeds from sale of bonds	–	93,658	–	–	–	–	80,750	322,582	–	496,990
Proceeds from bond escrow restructuring	17,292	–	–	–	–	–	–	–	–	17,292
Payment for defeasance of revenue bonds	–	(108,945)	–	–	–	–	(72,344)	–	–	(181,289)
Principal payments on debt	(47,395)	(26,695)	(905)	–	–	(6,600)	(1,600)	–	–	(83,195)
Transfer of funds from escrow	–	–	–	–	–	–	–	–	–	–
Payment for bond issue costs	(580)	(1,605)	(1,982)	–	–	–	(1,218)	(6,270)	–	(9,673)
Net cash provided by (used for) capital and related financing activities	(81,871)	(85,736)	(1,982)	(3,889)	(12,232)	(21,711)	(2,187)	232,193	–	22,585
Cash flows from investing activities:										
Interest received on investments	9,017	4,217	77	689	1,832	17,564	1,270	199	2,421	37,286
Purchases of investments	(550,977)	(47,544)	(4,122)	(609)	(4,894)	(1,188)	(15,553)	(75,783)	(92,323)	(792,993)
Proceeds from sale/maturity of investments	506,618	74,274	7,595	75	3,905	5,334	10,025	5,772	197,609	811,207
Net cash provided by (used for) investing activities	(35,342)	30,947	3,550	155	843	21,710	(4,258)	(69,812)	107,707	55,500
Net increase (decrease) in cash and cash equivalents	44,993	4,404	3,599	(464)	(1,103)	(1)	867	162,381	27,971	242,647
Cash and cash equivalents at beginning of year	60,149	33,532	127	2,081	3,894	1	15,063	–	14,970	129,817
Cash and cash equivalents at end of year	$ 105,142	$ 37,936	$ 3,726	$ 1,617	$ 2,791	$ –	$ 15,930	$ 162,381	$ 42,941	$ 372,464
Reconciliation of operating income to net cash provided by operating activities:										
Operating income (loss)	$ 106,879	$ 48,796	$ (51)	$ 2,430	$ 6,838	$ –	$ 13,853	$ –	$ –	$ 178,745
Adjustments to reconcile operating income to net cash provided (used) by operating activities:										
Depreciation	26,702	19,629	4	1,405	4,501	–	10,084	–	–	62,325
Decommissioning	10,900	–	–	–	–	–	3,113	–	–	14,013
Advances for capacity and energy	–	–	2,124	–	–	–	–	–	–	2,124
Amortization of nuclear fuel	8,586	–	–	–	–	–	–	–	–	8,586
Changes in assets and liabilities:										
Accounts receivable	201	(2,369)	–	–	(3)	–	(8,812)	–	–	(10,983)
Accounts payable and accruals	8,888	(5,829)	(56)	(565)	(1,058)	–	(10,855)	–	–	(9,475)
Other	50	(1,034)	10	–	8	–	(71)	–	–	(1,037)
Net cash provided by operating activities	$ 162,206	$ 59,193	$ 2,031	$ 3,270	$ 10,286	$ –	$ 7,312	$ –	$ –	$ 244,298

The accompanying notes are an integral part of the combined financial statements.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
COMBINED STATEMENTS OF CASH FLOWS
FOR THE YEAR ENDED JUNE 30, 2002
(Amounts in thousands)

	Year Ended June 30, 2002 (Restated)								
	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead-Phoenix Project	Mead-Adelanto Project	Multiple Project Fund	San Juan Project	Projects' Stabilization Fund	Total
Cash flows from operating activities:									
Receipts from participants	$ 184,347	$ 82,431	$ 2,568	$ 4,064	$ 10,737	$ –	$ 52,134	$ –	$ 336,281
Payments to operating managers	(24,762)	(16,959)	(270)	(1,168)	(1,037)	–	(43,887)	–	(88,083)
Other receipts (payments)	27	(622)	(6)	153	148	–	1,069	–	769
Net cash flow from operating activities	159,612	64,850	2,292	3,049	9,848	–	9,316	–	248,967
Cash flows from noncapital financing activities:									
Withdrawals by participants, net	–	–	–	–	–	–	–	(37,126)	(37,126)
Cash flows from capital and related financing activities:									
Additions to plant, net	(15,751)	–	–	78	3	–	(103)	–	(15,773)
Debt interest payments	(37,413)	(45,191)	(1,101)	(3,947)	(12,363)	(15,547)	(10,542)	–	(126,104)
Proceeds from sale of bonds	–	65,236	25,336	–	–	–	135,548	–	226,120
Payment for defeasance of revenue bonds	–	(76,183)	(28,816)	–	–	–	(124,828)	–	(229,827)
Principal payments on debt	(45,105)	(19,210)	(650)	(1,710)	(3,895)	(6,200)	(7,480)	–	(84,250)
Payment for bond issue costs	–	(1,301)	(627)	–	–	–	(1,530)	–	(3,458)
Net cash used for capital and related financing activities	(98,269)	(76,649)	(5,858)	(5,579)	(16,255)	(21,747)	(8,935)	–	(233,292)
Cash flows from investing activities:									
Interest received on investments	11,713	4,390	249	706	2,001	18,299	727	10,576	48,661
Purchases of investments	(516,905)	(36,833)	(7,024)	(1,682)	(6,415)	(8,857)	(23,561)	(68,403)	(669,680)
Proceeds from sale/maturity of investments	423,713	53,262	8,354	2,258	8,140	12,288	19,762	92,432	620,209
Net cash provided by (used for) investing activities	(81,479)	20,819	1,579	1,282	3,726	21,730	(3,072)	34,605	(810)
Net increase (decrease) in cash and cash equivalents	(20,136)	9,020	(1,987)	(1,248)	(2,681)	(17)	(2,691)	(2,521)	(22,261)
Cash and cash equivalents at beginning of year	80,285	24,512	2,114	3,329	6,575	18	17,754	17,491	152,078
Cash and cash equivalents at end of year	$ 60,149	$ 33,532	$ 127	$ 2,081	$ 3,894	$ 1	$ 15,063	$ 14,970	$ 129,817
Reconciliation of operating income to net cash provided by operating activities:									
Operating income (loss)	$ 104,108	$ 40,709	$ 116	$ 1,411	$ 5,815	$ –	$ (5,937)	$ –	$ 146,222
Adjustments to reconcile operating income to net cash provided (used) by operating activities:									
Depreciation	26,701	19,633	4	1,406	4,502	–	10,073	–	62,319
Decommissioning	11,872	–	–	–	–	–	3,113	–	14,985
Advances for capacity and energy	–	–	1,954	–	–	–	–	–	1,954
Amortization of nuclear fuel	8,259	–	–	–	–	–	–	–	8,259
Changes in assets and liabilities:									
Accounts receivable	47	–	33	–	371	–	1,168	–	1,619
Accounts payable and accruals	8,811	4,508	185	232	(840)	–	861	–	13,757
Other	(186)	–	–	–	–	–	38	–	(148)
Net cash provided by operating activities	$ 159,612	$ 64,850	$ 2,292	$ 3,049	$ 9,848	$ –	$ 9,316	$ –	$ 248,967

The accompanying notes are an integral part of the combined financial statements.

Note 1 – Organization and Purpose

The Southern California Public Power Authority (the "Authority"), a public entity organized under the laws of the State of California, was formed by a Joint Powers Agreement dated as of November 1, 1980 pursuant to the Joint Exercise of Powers Act of the State of California. The Authority's participants consist of eleven Southern California cities and one public district of the State of California. The Authority was formed for the purpose of planning, financing, developing, acquiring, constructing, operating and maintaining projects for the generation and transmission of electric energy for sale to its participants. The Joint Powers Agreement has a term of fifty years.

The Joint Powers Agreement authorizes the Authority to admit new members to the agreement. The Cities of Cerritos of Los Angeles County and San Marcos of San Diego County have applied for membership under the agreement. In July 2001, the Authority adopted a policy to establish the criteria for admitting new members. The two cities met all of the established criteria and became members to the agreement in July 2001. In August 2003, the Authority, by resolution of the Board of Directors (the "Board"), rescinded the membership of the City of San Marcos, as the city no longer met the criteria for membership.

The Authority has interests in the following projects:

Palo Verde Project – On August 14, 1981, the Authority purchased a 5.91% interest in the Palo Verde Nuclear Generating Station ("PVNGS"), a 3,810 megawatt nuclear-fueled generating station near Phoenix, Arizona, and a 6.55% share of the right to use certain portions of the Arizona Nuclear Power Project Valley Transmission System (collectively, the "Palo Verde Project"). Units 1, 2 and 3 of the Palo Verde Project began commercial operations in January 1986, September 1986, and January 1988, respectively.

Southern Transmission System Project – On May 1, 1983, the Authority entered into an agreement with the Intermountain Power Agency ("IPA"), to defray all the costs of acquisition and construction of the Southern Transmission System Project ("STS") which provides for the transmission of energy from the Intermountain Generating Station in Utah to Southern California. STS commenced commercial operations in July 1986. The Department of Water and Power of the City of Los Angeles ("LADWP"), a member of the Authority, serves as project manager and operating agent of the Intermountain Power Project ("IPP").

Hoover Uprating Project – As of March 1, 1986, the Authority and six participants entered into an agreement pursuant to which each participant assigned its entitlement to capacity and associated firm energy to the Authority in return for the Authority's agreement to make advance payments to the United States Bureau of Reclamation ("USBR") on behalf of such participants. The Authority has an 18.68% interest in the contingent capacity of the Hoover Uprating Project ("HU").

Mead-Phoenix and Mead-Adelanto Projects – As of December 17, 1991, the Authority entered into an agreement to acquire an interest in the Mead-Phoenix Project ("Mead-Phoenix"), a transmission line extending between the Westwing substation in Arizona and the Marketplace substation in Nevada. The agreement provides the Authority with an 18.31% interest in the Westwing-Mead project component, a 17.76% interest in the Mead Substation project component and a 22.41% interest in the Mead-Marketplace project component.

As of December 17, 1991, the Authority also entered into an agreement to acquire a 67.92% interest in the Mead-Adelanto Project ("Mead-Adelanto"), a transmission line extending between the Adelanto substation in Southern California and the Marketplace substation in Nevada. Funding for these projects was provided by a transfer of funds from the Multiple Project Fund and commercial operations commenced in April 1996. LADWP serves as the operations manager of Mead-Adelanto.

Multiple Project Fund – During fiscal year 1990, the Authority issued Multiple Project Revenue Bonds for net proceeds of approximately $600 million to provide funds to finance costs of construction and acquisition of ownership interests or capacity rights in one or more, then unspecified, projects for the generation or transmission of electric energy. Certain of these funds were used to finance the Authority's interests in Mead-Phoenix and Mead-Adelanto.

San Juan Project – Effective July 1, 1993, the Authority purchased a 41.80% interest in Unit 3 and related common facilities, of the San Juan Generating Station ("SJGS") from Century Power Corporation. Unit 3, a 488 megawatt unit, is one unit of a four-unit coal-fired power generating station in New Mexico.

Magnolia Power Project ("The Project") – In March 2003, the Authority received approval from the California Energy Commission for construction of the Magnolia Power Project. The Project will consist of a combined cycle natural gas-fired generating plant with a nominally rated net base capacity of 242 megawatts and will be built on a site in the City of Burbank, California. The plant is the first that is wholly owned by the Authority and entitlements to 100% of the capacity and energy of the Project have been sold to six of its members. The City of Burbank, a Project participant, will manage its construction and operation. Construction is under way and commercial operation is expected to begin in mid-2005. During the current year, the Project had no revenues and is not anticipated to have any until the Project becomes operational. Costs related to the construction of the plant of $91.6 million and debt service costs of $3.7 million offset by investment income of $1.7 million, were capitalized as part of the utility plant balance. Once the plant becomes operational, these costs will be recovered through future billings to participants.

Projects' Stabilization Fund – In fiscal year 1997, the Authority authorized the creation of a Projects' Stabilization Fund. Deposits may be made into the fund from budget under-runs, after authorization of individual participants, and by direct contributions from the participants. Participants have discretion over the use of their deposits within SCPPA project purposes. This fund is not a project-related fund; therefore, it is not governed by any project Indenture of Trust.

The members participate in the Projects' Stabilization Fund by making deposits to the fund at their discretion.

Participant Ownership Interests – The Authority's participants may elect to participate in the projects. As of June 30, 2003, the members have the following participation percentages in the Authority's interest in the projects:

Participants	Palo Verde	STS	Hoover Uprating	Mead-Phoenix	Mead-Adelanto	San Juan	Magnolia Power Project
City of Los Angeles	67.0%	59.5%		24.8%	35.7%		
City of Anaheim		17.6%	42.6%	24.2%	13.5%		38.0%
City of Riverside	5.4%	10.2%	31.9%	4.0%	13.5%		
Imperial Irrigation District	6.5%					51.0%	
City of Vernon	4.9%						
City of Azusa	1.0%		4.2%	1.0%	2.2%	14.7%	
City of Banning	1.0%		2.1%	1.0%	1.3%	9.8%	
City of Colton	1.0%		3.2%	1.0%	2.6%	14.7%	4.2%
City of Burbank	4.4%	4.5%	16.0%	15.4%	11.5%		31.0%
City of Glendale	4.4%	2.3%		14.8%	11.1%	9.8%	16.5%
City of Cerritos							4.2%
City of Pasadena	4.4%	5.9%		13.8%	8.6%		6.1%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100%

The Authority has entered into power sales and transmission service agreements with the above project participants. Under the terms of the contracts, the participants are entitled to power output or transmission service, as applicable. The participants are obligated to make payments on a "take or pay" basis for their proportionate share of operating and maintenance expenses and debt service. The contracts cannot be terminated or amended in any manner which will impair or adversely affect the rights of the bondholders as long as any bonds issued by the specific project remain outstanding.

The contracts expire as follows:

Palo Verde Project	2030
Southern Transmission System Project	2027
Hoover Uprating Project	2018
Mead-Phoenix Project	2030
Mead-Adelanto Project	2030
San Juan Project	2030
Magnolia Power Project	2036

The Authority's interests in generation and transmission projects are jointly owned with other utilities. Each joint plant participant, including the Authority, is responsible for financing its share of construction and operating costs. The financial statements reflect the Authority's interest in each jointly-owned project as well as the project that it owns.

2. Summary of Significant Accounting Policies

The accounting records of the Authority are maintained in accordance with accounting principles generally accepted in the United States of America. As a government-owned utility, in prior years the Authority applied all statements issued by the Governmental Accounting Standards Board (GASB) and all statements and interpretations issued by the Financial Accounting Standards Board (FASB) which were not in conflict with statements issued by the GASB. Effective July 1, 2002, the Authority changed its election under the guidance in GASB Statement No. 20, *Accounting and Financial Reporting for Proprietary Funds and Other Governmental Entities that Use Proprietary Fund Accounting*, to follow all GASB statements and only FASB statements and interpretations issued before November 30, 1989.

Accounting Changes

Change in Election of Application of GASB 20 – Effective July 1, 2002, the Authority changed its election under the guidance in GASB 20 and no longer follows FASB statements issued after November 30, 1989. The impact on the Authority's financial statements as a result of this change was the discontinuation of the application of FASB Statement No. 133, *Accounting for Derivative Instruments and Hedging Activities* (FASB 133). The Authority adopted FASB 133 in fiscal year 2001 and consequently began reporting its derivative instruments at fair value. With this accounting change, the Authority is no longer required to report its derivative instruments at fair value under the guidance applicable to state and local governments. The Authority restated its prior year financial statements to retroactively apply this change in election under GASB 20. The Authority believes that this was a change to a preferable method of accounting. The restatement of the fiscal year 2002 financial statements was limited to STS, as it was the only project with derivative instruments.

Included in the derivative commitments caption in the prior years was the $7.9 million premium received by the Authority in consideration for entering into an agreement whereby the Authority sold an option ("the Swaption") on a floating-to-fixed interest rate swap. Previously the value of this option was recorded at fair value; however, with this change in accounting principle, it is now reported as part of the debt value and amortized to interest expense as a downward yield adjustment over the life of the related debt. See Note 4 for derivative instrument disclosures.

The following summarizes the impact on the combined financial statements from this change in accounting principle:

	As Previously Reported	Adjustments	As Restated
	June 30, 2002		
Combined Statements of Net Assets (Deficit)			
Long-term debt	$2,166,175	$ 7,272	$2,173,447
Derivative commitments	$ 99,695	$ (99,695)	$ –
Net assets (deficit)	$ (285,632)	$ 92,423	$ (193,209)
	Year Ended June 30, 2002		
Combined Statements of Revenues, Expenses and Changes in Net Assets (Deficit)			
Debt expenses	$ (163,701)	$ 443	$ (163,258)
Unrealized loss on derivative commitment	$ (36,675)	$ 36,675	$ –
Net assets (deficit) -beginning of year (June 30, 2001)	$ (272,197)	$ 55,305	$ (216,892)

Adoption of GASB Statements Nos. 34, 37, and 38 – On July 1, 2001, the Authority adopted GASB Statement No. 34 (GASB 34), *"Basic Financial Statements and Management's Discussion and Analysis for State and Local Governments"*; GASB Statement No. 37 (GASB 37), *"Basic Financial Statements and Management's Discussion and Analysis for State and Local Governments: Omnibus – an Amendment of GASB Statements No. 21 and No. 34" and GASB Statement No. 38 "Certain Financial Statement Note Disclosures"* (GASB 38). GASB 34, as amended, and GASB 38 establish specific standards for external financial reporting for all state and local governments. As a result of adopting these Standards, the basic financial statement presentation was significantly changed, including adding management's discussion and analysis of operating, investing and financing activities. GASB 34 also requires the classification of net assets (deficit) into three components – invested in capital assets, net of related debt; restricted; and unrestricted. These classifications are defined as follows:

- **Invested in capital assets, net of related debt** – This component of net assets consists of (a) capital assets, (b) net of accumulated depreciation and (c) unamortized debt expenses, reduced by the outstanding balances of any bonds or other borrowings that are attributable to the acquisition, construction, or improvement of

those assets. If there are significant unspent related debt proceeds at year-end, the portion of the debt attributable to the unspent proceeds is not included in the calculation of Invested in capital assets, net of related debt. Rather, that portion of the debt is included in the same net assets component as the unspent proceeds.

- **Restricted** – This component consists of net assets on which constraints are placed as to their use. Constraints include those imposed by creditors (such as through debt covenants), contributors, or laws or regulation of other governments or constraints imposed by law through constitutional provisions or through enabling legislation.

- **Unrestricted net assets** – This component of net assets consists of net assets that do not meet the definition of "restricted" or "invested in capital assets, net of related debt."

Under GASB 34, the statements of equity and of other comprehensive income were eliminated; the statement of income was renamed the statement of revenues, expenses and changes in net assets (deficit); and the statement of cash flows presentation was changed to the direct method (including a reconciliation of operating cash flows to operating income). The adoption of GASB 34 had no significant effect on the basic combined financial statements, except for the change from the indirect method to the direct method of reporting cash flows and the reclassification of cost recoverable, deferred credits and funds due to participants to net assets (deficit) in accordance with the Statement.

Use of Estimates – The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Utility Plant – The Authority's share of construction and betterment costs associated with PVNGS, STS, Mead-Phoenix, Mead-Adelanto, SJGS and Magnolia Power Project are included as utility plant. Depreciation expense is computed using the straight-line method based on the estimated service lives, principally thirty-five years for PVNGS, STS, Mead-Phoenix and Mead-Adelanto and twenty-one years for SJGS.

A summary of changes in Utility plant follows (amounts in thousands):

	Balance June 30, 2002	Additions	Disposals	Transfers	Balance June 30, 2003
Nondepreciable Utility Plant					
Land	$ 36,187	$ –	$ –	$ –	$ 36,187
Construction work in progress	15,180	101,904	–	(4,339)	112,745
Nuclear fuel*	14,981	5,892	(6,329)	–	14,544
Total nondepreciable utility plant	66,348	107,796	(6,329)	(4,339)	163,476
Depreciable Utility Plant					
Production					
Nuclear generation (Palo Verde Project)	620,003	3,247	(614)	–	622,636
Coal-fired plant (San Juan Unit 3 Project)	175,111	868	(3,504)	–	172,475
Transmission	876,286	–	–	–	876,286
General	32,718	224	(124)	–	32,818
Total depreciable utility plant	1,704,118	4,339	(4,242)	–	1,704,215
Less accumulated depreciation	(892,551)	(76,337)	4,216	–	(964,672)
Total utility plant, net	$ 877,915	$ 35,798	$ (6,355)	$ (4,339)	$ 903,019

*Nuclear fuel disposals represent amortization.

Nuclear Fuel – Nuclear fuel is amortized and charged to expense on the basis of actual thermal energy produced relative to total thermal energy expected to be produced over the life of the fuel. Under the provisions of the Nuclear Waste Policy Act of 1982, the federal government assesses each entity with nuclear operations, including the participants in PVNGS, $1 per megawatt hour of nuclear generation. The Authority records this charge as a current year expense. See Note 7 for information about spent nuclear fuel disposal.

Nuclear Decommissioning – Decommissioning of PVNGS is expected to commence subsequent to the year 2024. The total cost to decommission the Authority's interest in PVNGS is estimated to be $116.6 million in 2002 dollars ($375.0 million in 2022 dollars, assuming a 6% estimated annual inflation rate). This estimate is based on an updated site specific study prepared by an independent consultant in 2001. The Authority is providing for its share of the estimated future decommissioning costs over the remaining life of the nuclear power plant through annual charges to expense, which amounted to $10.9 and $11.9 million in fiscal years 2003 and 2002, respectively. The decommissioning liability is included as a component of accumulated depreciation and was $170.8 and $159.9 million at June 30, 2003 and 2002, respectively.

The Authority contributes to external trusts set up in accordance with the Arizona Nuclear Power Plant participation agreement and Nuclear Regulatory Commission requirements. As of June 30, 2003, decommissioning funds totaled approximately $117.8 million, including approximately $902,000 of interest receivable.

Demolition and Site Reclamation – Demolition and site reclamation of SJGS, which involves restoring the site to a "green" condition, is projected to commence subsequent to the year 2014. Based upon the study performed by an independent engineering firm, the Authority's share of the estimated demolition and site reclamation costs is $18.7 million in 1992 dollars. The Authority is providing for its share of the estimated future demolition costs over the remaining life of the power plant through annual charges to expense of $3.1 million. The demolition liability is included as a component of accumulated depreciation and totaled $31.1 million and $28.0 million at June 30, 2003 and 2002, respectively.

As of June 30, 2003, the Authority has not billed participants for the cost of demolition nor has it established a demolition fund.

Investments – Investments include United States government and governmental agency securities and repurchase agreements which are collateralized by such securities. These investments are reported at fair value and changes in unrealized gains and losses are recorded in the statement of revenues, expenses and changes in net assets (deficit). Gains and losses realized on the sale of investments are generally determined using the specific identification method.

The Bond Indentures for the six Projects and the Multiple Project Fund require the use of trust funds to account for the Authority's receipts and disbursements. Cash and investments held in these funds are restricted to specific purposes as stipulated in the Bond Indentures.

Advances for Capacity and Energy – Advance payments to the United States Bureau of Reclamation for the uprating of the 17 generators at the Hoover Power Plant are included in advances for capacity and energy. These advances are being reduced by the principal portion of the credits on billings to the Authority for energy and capacity.

Cash and Cash Equivalents – Cash and cash equivalents include cash and investments with original maturities of 90 days or less.

Unamortized Debt Expenses – Debt premiums, discounts and issue expenses are deferred and amortized to expense over the lives of the related debt issues. Losses on refunding related to bonds redeemed by refunding bonds are amortized over the shorter of the life of the refunding bonds or the remaining term of bonds refunded. Losses on early extinguishment of debt are recognized immediately.

Arbitrage Rebate – The unused proceeds from the issuance of Multiple Project Revenue Bonds have been invested in taxable financial instruments. The excess of interest income over expense associated with the bonds, if any, is payable to the IRS within five years of the date of the bond offering and each consecutive five years thereafter.

At June 30, 2003, cumulative savings due to the rebate calculation amounted to $14.4 million. As a result, the Multiple Project Fund has recorded liabilities of $3.8 million and $10.6 million to the Mead-Phoenix Project and Mead-Adelanto Projects, respectively.

The next rebate payment to the IRS for these issues, if any, is due in fiscal year 2006.

Revenues – Revenues consist of billings to participants for the sales of electric energy and transmission service in accordance with the participation agreements. Generally, revenues are fixed at a level to recover all operating and debt service costs over the commercial life of the property.

In September 1998, the Palo Verde participants approved a resolution authorizing the Authority to bill the participants $65 million annually through June 30, 2004 to pay for increased debt service costs as a result of a refunding completed in October 1997. In addition, the participants resolved to transfer any overbillings, renewal and replacement excess funds or surplus amounts through June 30, 2004 into the Palo Verde reserve account. Amounts on deposit in the reserve account are intended to be used to enhance the competitiveness of the Palo Verde Project, at the discretion of the Board of Directors. Funds held in the reserve account as a result of this resolution totaled $45.5 million and $34.8 million as of June 30, 2003 and 2002, respectively.

San Juan Coal Agreements – On October 17, 2000, an agreement was reached on the principles of a new long-term fuel sourcing and pricing plan between the participants of SJGS and its coal supplier. The agreement authorizes the supplier to develop an underground longwall mine to replace production from two existing surface mines. To terminate the existing agreement, the Authority made a $9.9 million payment on December 31, 2002, which was its share of the requirement of the new contract. Included in the current year revenues are billings to project participants for the required proceeds to settle the $9.9 million buyout. The new underground mine will result in significantly reduced costs of coal supplied to SJGS through 2017, the term of the new contract.

Reclassifications – Certain prior period amounts have been reclassified to conform to the current presentation.

3. Investments

The Authority's investment function operates within a legal framework established by Sections 6509.5 and 53600 et. Seq. of the California Government Code, Indentures of Trust, instruments governing financial arrangements entered into by SCPPA to finance and operate Projects and the SCPPA Investment Policy.

Eligible securities and general limitations are derived from each Project's Indenture of Trust for the issuance of senior and subordinate lien bonds. Additional limitations are derived from the Government Code and SCPPA's evolving investment practices.

The operative Indentures of Trust in which securities are authorized for investment purposes relate to the Hoover Uprating Project Bonds, the San Juan Project Bonds, the Palo Verde Project Bonds, the Southern Transmission System Project Bonds, the Mead-Phoenix Project Bonds, the Mead-Adelanto Project Bonds, the Multiple Project Fund Bonds and the Magnolia Power Project Bonds. Authorized investments for the Projects' Stabilization Fund are set forth in a resolution approved by the Board in 1996.

Eligible securities include:

- United States Treasury Securities, which are bonds or other obligations secured by the full faith and credit of the United States of America;
- Federal Agency Obligations, which have the full financial backing of the U.S. Government;
- Government Sponsored Enterprise Obligations, which are created by acts of Congress to provide liquidity for selected lending programs targeted by Congress;
- Repurchase Agreements, which are collateralized loan contracts where the seller includes a written agreement to repurchase the securities at a later date for a specified amount;
- Negotiable Certificates of Deposit, which are deposit liabilities issued by a nationally or state-chartered bank, a savings or a federal association or by a state-licensed branch of a foreign bank which has a short-term ratings of at least "A-1" by S&P and at least "P-1" by Moody's;
- Banker's Acceptances, a short term draft or bill of exchange guaranteed for payment at face value to the holder of the instrument on its maturity date, which has a short-term rating of at least "A-1" by S&P and at least "P-1" by Moody's;
- Commercial Paper, a short-term unsecured promissory note issued by non-financial or financial firms with a rating of "A-1" by S&P and "P-1" by Moody's;
- Medium Term Notes rated "A" or better and only those issued by corporations organized and operating within the United States, or by depository institutions licensed by the United States or any state and operating within the United States;
- Equity-Linked Notes, which are categorized as medium-term corporate notes and are subject to the constraints set forth in the Government code.

Investments at June 30, 2003 and 2002 are as follows:

	June 30, 2003									
	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead-Phoenix Project	Mead-Adelanto Project	Multiple Project Fund	San Juan Project	Magnolia Power Project	Projects' Stabilization Fund	Total
Federal agencies	$ 351,717	$ 40,265	$ 2,955	$ 437	$ 3,283	$ 7,435	$ 15,514	$ 46,945	$ 89,239	$ 557,790
U.S. government securities	420,763	10,337	–	–	–	–	–	–	5,711	436,811
Guaranteed investment contracts	–	36,423	–	9,314	24,898	236,002	21,599	35,397	–	363,633
Repurchase agreements	–	–	–	–	–	–	–	–	–	–
Money market investment account	3,123	9,673	1,253	1,605	2,069	–	397	150,465	1,035	169,620
Medium term notes	4,367	–	–	–	–	–	–	–	–	4,367
Cash	96	40	18	12	12	–	22	–	–	200
Total	$ 780,066	$ 96,738	$ 4,226	$ 11,368	$ 30,262	$ 243,437	$ 37,532	$ 232,807	$ 95,985	$ 1,532,421
Restricted investments	$ 661,929	$ 58,802	$ –	$ 9,751	$ 27,471	$ 243,437	$ 21,602	$ 70,426	$ 53,044	$ 1,146,462
Unrestricted investments	12,995	–	500	–	–	–	–	–	–	13,495
Cash and cash equivalents	105,142	37,936	3,726	1,617	2,791	–	15,930	162,381	42,941	372,464
Total	$ 780,066	$ 96,738	$ 4,226	$ 11,368	$ 30,262	$ 243,437	$ 37,532	$ 232,807	$ 95,985	$ 1,532,421

	June 30, 2002								
	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead-Phoenix Project	Mead-Adelanto Project	Multiple Project Fund	San Juan Project	Projects' Stabilization Fund	Total
Federal agencies	$ 304,433	$ 44,247	$ 3,972	$ 1,815	$ 5,015	$ 7,435	$ 16,668	$ 156,067	$ 539,652
U.S. government securities	290,244	15,094	–	–	–	–	–	13,104	318,442
Guaranteed investment contracts	–	40,412	–	9,209	24,906	240,149	13,524	–	328,200
Repurchase agreements	–	6,559	–	–	–	–	–	–	6,559
Money market investment account	3,389	10,656	105	254	422	1	903	3,088	18,818
Medium term notes	4,500	–	–	–	–	–	–	–	4,500
Cash	96	38	22	12	12	–	20	1,031	1,231
Total	$ 602,662	$ 117,006	$ 4,099	$ 11,290	$ 30,355	$ 247,585	$ 31,115	$ 173,290	$ 1,217,402
Restricted investments	$ 528,985	$ 83,474	$ 2,861	$ 9,209	$ 26,461	$ 247,584	$ 16,052	$ 158,320	$ 1,072,946
Unrestricted investments	13,528	–	1,111	–	–	–	–	–	14,639
Cash and cash equivalents	60,149	33,532	127	2,081	3,894	1	15,063	14,970	129,817
Total	$ 602,662	$ 117,006	$ 4,099	$ 11,290	$ 30,355	$ 247,585	$ 31,115	$ 173,290	$ 1,217,402

4. Derivative Instruments

Objective of the swaps. In order to protect against the potential of rising interest rates, the Authority entered into four separate pay-fixed, receive-variable interest rate swaps at a cost less than what the Authority would have paid to issue fixed-rate debt.

Terms, fair values, and credit risk. The terms, including the fair values and credit ratings of the outstanding swaps as of June 30, 2003, are included below. The notional amounts of the swaps match the principal amounts of the associated debt. Except as discussed under the rollover risk, the Authority's swap agreements contain scheduled reductions to outstanding notional amounts that are expected to approximately follow scheduled or anticipated reductions in the associated "bonds payable" category.

- *2003 Swap* – In April 2003, the Authority entered into an Interest Rate Swap agreement with a third party for the purpose of hedging against interest rate variations arising from the issuance of the 2003 Subordinate Refunding Series A Southern Transmission System Project Revenue Bonds. The notional amount of the Swap Agreement is equal to the par value of the bonds. The Swap Agreement provides for the Authority to make payments to the third party on a fixed rate basis of 3.266%, and for the third party to make reciprocal payments based on a floating rate priced at 65% of one-month LIBOR. The floating rate on the related bonds at June 30, 2003 was 0.857%. The termination of the agreement is July 1, 2022.

- *Swaption/2000 Swap* – In February 2001, the Authority entered into a transaction whereby it sold an option ("the Swaption") on a floating-to-fixed interest rate swap. The Swaption, if exercised, will effectively convert the $125 million Subordinate Refunding Series A bonds issued by the Southern Transmission System Project in May 2000, into a synthetic fixed-rate debt obligation with a coupon of 4.25%. The floating rate on the Swaption is priced at 60% of one-month LIBOR. In exchange for the right to exercise the swaption, the counterparty paid the Authority a one-time up front option premium amount of $7.9 million.

  On April 1, 2002, the counterparty exercised its option and the Authority is now obligated to pay floating for fixed payments on the 2000 Subordinate Refunding Series A bonds based on the terms described above. The floating rate on the related bonds at June 30, 2003 and 2002 was 0.95% and 1.11%, respectively.

- *2001 Swap* – In June 2001, the Authority entered into an interest rate swap agreement with a third party for the purpose of hedging against interest rate variations arising from the issuance of the 2001 Subordinate Refunding Series A Southern Transmission System Project Revenue Bonds. The notional amount of the Swap Agreement is equal to the par value of the bonds. The Swap Agreement provides for the Authority to make payments to the third party on a fixed rate basis of 4.24%, and for the third party to make reciprocal payments based on a variable rate. The reset dates of the variable rate occur weekly and the rate for a reset date will be the rate determined by the Bond Market Association Municipal Swap Index ("BMA") minus 40 basis points. The counterparty has the option to terminate the agreement on or after July 1, 2006 should the BMA index average more than 7% over a consecutive 180-day period. The floating rates on the bonds were 0.95% and 1.10% at June 30, 2003 and 2002, respectively. The bonds mature in 2021.

- *1991 Swap* – In fiscal year 1991, the Authority entered into an Interest Rate Swap Agreement with a third party for the purpose of hedging against interest rate fluctuations arising from the issuance of 1991 Subordinate Refunding Series Southern Transmission Project Revenue Bonds. The notional amount of the Swap Agreement is equal to the par value of the bonds. The Swap Agreement provides for the Authority to make payments to the third party on a fixed rate basis at 6.38%, and for the third party to make reciprocal payments mirroring the bond variable coupon rate (0.85% and 1.10% at June 30, 2003 and 2002, respectively). The bonds mature in 2019.

Fair value. Because interest rates have declined since inception date of each swap, all swaps had negative fair value as of June 30, 2003. All fair values were estimated using the zero-coupon method. This method calculates the future payments required by the swap, assuming that the current forward rates implied by the yield curve correctly anticipate future spot interest rates. These payments are then discounted using the spot rates implied by the current yield curve for hypothetical zero-coupon rate bonds due on the date of each future net settlement on the swaps.

Credit risk. As of June 30, 2003, the Authority was not exposed to credit risk on any of its outstanding swaps because the swaps had negative fair values. However, should interest rates change and the fair values of the swaps become positive, the Authority would be exposed to credit risk in the amount of the derivatives' fair value.

The swap agreements contain varying collateral agreements with the counterparties. The swaps require full collateralization of the fair value of the swap should the counterparty's credit rating fall below A – as issued by Standard & Poor's or A3 as issued by Moody's Investors Service for the 1991 Swap, AA-/Aa3 for the 2000 swap, and A3/A1 for the 2001 swap. Collateral on all swaps is to be in the form of US government securities held by a third-party custodian.

(Amounts in thousands)

Associated Bond Issues	Notional Amount	Effective Date	Fixed Rate Paid	Variable Rate Received	Fair Values	Swap Termination Date	Counterparty Credit Rating
STS 1991 Revenue Bonds Series A	$ 285,400	4/17/1991	6.38%	Bond variable coupon rate	$ (100,134)	6/30/2019	AAA/Aaa
STS 2000 Subordinate Refunding Series A Bonds	125,000	2/1/2001	4.25%	60% of LIBOR	(31,398)	7/1/2022	AA-/Aa1
STS 2001 Subordinate Refunding Series A Bonds	79,795	6/14/2001	4.24%	BMA less 40 basis points	(14,470)	7/1/2021	AA+/Aa2
STS 2003 Subordinate Refunding Series A Bonds	51,750	4/24/2003	3.266%	65% of LIBOR	(2,068)	7/1/2022	AA-/Aa1
	$ 541,945				$ (148,070)		

The Authority also enters into master netting agreements when the Authority has more than one derivative transaction with one counterparty. Under the terms of these agreements, should one party become insolvent or otherwise default on its obligations, close-out netting provisions permit the nondefaulting party to accelerate and terminate all outstanding transactions and net the transactions' fair values so that a single sum will be owed by, or owed to, the nondefaulting party.

Basis risk. The Authority's variable-rate bond coupon payment for the 2001 swap is based on the BMA rate. For the 2000 and 2003 swaps for which the Authority receives a variable-rate payment other than BMA, the Authority is exposed to basis risk should the relationship between LIBOR and BMA converge. If a change occurs that results in the rates moving to convergence, the expected cost savings may not be realized. As of June 30, 2003, the BMA rate was 0.635%, whereas 60% of LIBOR was 0.792%, and 65% of LIBOR was 0.857 %. The following is a summary of interest rates paid and received from the counterparties as of June 30, 2003:

	Type of Derivative			
	1991 Swap	2000 Swap	2001 Swap	2003 Swap
Fixed payments to counterparty	6.380%	4.250%	4.240%	3.266%
Less, variable payments from counterparty	0.850%	0.792%	0.635%	0.857%
Net interest rate swap payments	5.530%	3.458%	3.605%	2.409%
Add, variable-rate bond coupon payments	0.850%	0.950%	0.950%	0.850%
Synthetic interest rate on bonds	6.380%	4.408%	4.555%	3.259%

Termination risk. The Authority or the counterparty may terminate any of the swaps if the other party fails to perform under the terms of the contract. In addition, the 2001 Swap provides the counterparty with the option to terminate the swap agreement commencing July 1, 2006. If any of the swaps are terminated, the associated variable-rate bonds would no longer carry synthetic interest rates. If at the time of termination the swap has a negative fair value, the Authority would be liable to the counterparty for a payment equal to the swap's fair value.

Rollover risk. The Authority is exposed to rollover risk on the 2001 swap as the counterparty has the option to terminate the agreement prior to the maturity of the associated debt should the BMA index average more than 7% over a consecutive 180-day period. When this swap terminates, the Authority will not realize the synthetic rate offered by the swap on the underlying debt issue. The following debt is exposed to rollover risk:

Associated Debt Issuance	Debt Maturity Date	Optional Swap Termination Date
STS 2001 Subordinate Refunding Series A	7/01/2021	July 5, 2006

Swap payments and associated debt. Using rates as of June 30, 2003, debt service requirements of the Authority's outstanding variable-rate debt and net swap payments are as follows. As rates vary, variable-rate bond interest payments and net swap payments will vary.

Fiscal Year Ending June 30	Variable-Rate Bonds Principal	Variable-Rate Bonds Interest	Interest Rate Swaps, Net	Total
2004	$ 1,575	$ 4,798	$ 24,310	$ 29,108
2005	1,725	4,783	24,217	29,000
2006	1,850	4,768	24,119	28,887
2007	1,950	4,751	24,014	28,765
2008	14,875	4,625	23,197	27,822
2009-2013	134,900	20,267	99,388	119,655
2014-2018	247,220	9,829	48,218	58,047
2019-2022	137,850	1,633	6,088	7,721
	$ 541,945	$ 55,454	$ 273,551	$ 329,005

5. Long-Term Debt

Long-term debt outstanding at June 30, 2003 consists of revenue bonds and subordinate refunding bonds due serially in varying annual amounts through 2036. The revenue bonds were issued to finance the purchase and construction of the Authority's share of each of the Projects. The subordinate refunding bonds were issued to advance refund specified revenue bonds. The Multiple Project Revenue Bonds were issued on August 1, 1989 to finance acquisition of ownership interests in one or more Projects expected to be undertaken within five years after issuance. In October 1992, $103.6 million and $285.0 million of these bonds were transferred to the Mead-Phoenix Project and the Mead-Adelanto Project, respectively.

In accordance with the bond indentures, the revenue bonds and subordinate refunding bonds are special, limited obligations of the Authority. With the exception of the Magnolia Power Project B, Lease Revenue bonds (City of Cerritos, California) 2003-1 ("Project B Bonds"), the bonds issued by each project are payable solely from and secured solely by interests in the issuing project as follows:

- Proceeds from the sale of bonds;
- All revenues, incomes, rents and receipts attributable to the issuing project and related interest on securities held under the bond indentures; and
- All funds established by the indentures.

The Authority has agreed to certain covenants with respect to bonded indebtedness, including the requirement to enforce the power and transmission sales agreements with the participants. At the option of the Authority, all outstanding Power Project Revenue Bonds and Subordinate Refunding Term Bonds are subject to redemption prior to maturity, except for the 1996 Subordinate Refunding Series A and portions of the 1989A, 1992A, 1992B and 1993A Series bonds issued by the Palo Verde Project; the 1996 Subordinate Refunding Series A bonds issued by the Southern Transmission System; and, a total of $125.5 million of the outstanding Multiple Project Revenue Bonds.

Revenue Bonds

Magnolia Power Project Revenue Bonds – To finance the acquisition and construction of the Magnolia Power Project, the Authority, on April 2003, issued $299.975 million Magnolia Power Project A, Revenue Bonds, 2003-1 ("Project A Bonds"). Simultaneously with the issuance of the Project A Bonds, the Authority issued $14.105 million Project B Bonds. The Project Manager expects that proceeds of both the Project A and Project B Bonds, together with applicable interest earnings, will be sufficient to pay all costs necessary to construct and acquire the Project.

The Project B Bonds will be secured by lease rental payments to be made by the City of Cerritos (the "City") in connection with the lease of certain facilities and premises owned by the City to the Authority and the leaseback of such facilities and premises to the City. The Base Rental Payments will be equal to the principal and interest on the Project B Bonds. In accordance with the Assignment Agreement between the Authority and the Trustee, the Authority will assign certain of its rights under the Lease, including its right to receive the Base Rental Payments, to the Trustee for the benefit of the Owners of the Project B Bonds.

The City has covenanted to budget and appropriate sufficient funds to make all payments required to be made under the Lease. The Lease has a term of 55 years.

The bonds mature on July 1, 2036.

Hoover Uprating Project Refunding – In December 2001, the Authority issued $24.7 million par value Hoover 2001 Refunding Series A Bonds ("refunding bonds") to refund $28.1 million of Hoover 1991 Refunding Series A Bonds ("refunded bonds"). The remaining amount of $3.4 million was funded through the release of funds from the debt service accounts related to the refunded bonds. The refunded bonds were redeemed on January 1, 2002. The refunding is expected to reduce total debt service payments over the life of the refunding issue by approximately $9.3 million and is expected to result in present value savings of approximately $2.9 million based on an average cost of 4.74% on the new bonds.

This transaction resulted in a net loss for accounting purposes of $5.0 million, consisting primarily of the write-off of unamortized debt expense, deferred loss on prior refunding and the discount associated with the refunded bonds. The Authority has proportionately allocated this loss between bonds refunded through funds released from the debt service accounts and through the issuance of refunding bonds. The loss allocated to the new bonds of $4.3 million was deferred and will be amortized over the life of the new bonds. The portion refunded with cash resulted in immediate recognition of a $0.7 million extraordinary loss in fiscal year 2002.

San Juan Unit 3 Project Refunding – In October 2002, the Authority issued $71.85 million par value SJ 2002 Refunding Series B Bonds ("refunding bonds") to refund $70.8 million of SJGS 1993 Series A Bonds ("refunded bonds"). The refunding bonds are being issued as Auction Rate Certificates ("ARCs"). The initial interest period of the refunding bonds commenced from the date of delivery of the bonds and ends on January 1, 2012. During this period the interest payable on the bonds will accrue at 5.25% per annum. After the initial interest period, the refunding bonds will bear interest at the applicable Auction Rate. The Auction Dates for the 2002 Series B Bonds will generally occur every thirty-five (35) days.

The refunding is expected to reduce total debt service payments over the life of the refunding issue by approximately $12.9 million and is expected to result in present value savings of approximately $8.1 million based on an average cost of 4.80% on the new bonds. The refunded bonds were redeemed on January 1, 2003.

This transaction resulted in a net loss for accounting purposes of $6.04 million, consisting primarily of the write-off of unamortized debt expense and the discount associated with the refunded bonds. The Authority has proportionately allocated this loss between bonds refunded through funds released from the debt service accounts and through the issuance of refunding bonds. The loss allocated to the new bonds of $5.97 million was deferred and will be amortized over the life of the new bonds. The portion refunded with cash resulted in immediate recognition of a $74 thousand extraordinary loss in fiscal year 2003.

In May 2002, the Authority issued $125.3 million par value SJ 2002 Refunding Series A Bonds ("refunding bonds") to refund $118.1 million of SJ 1993 Revenue Series A Bonds ("refunded bonds"). The refunded bonds were redeemed beginning on January 1, 2003 and will continue to be redeemed as they become due every January 1 through January 1, 2014. The refunding is expected to reduce total debt service payments over the life of the refunding issue by approximately $8.9 million and is expected to result in present value savings of approximately $4.0 million based on an average cost of 5.33% on the new bonds.

This transaction resulted in a net loss for accounting purposes of $7.3 million, consisting primarily of the write-off of unamortized debt expense and the discount associated with the refunded bonds. The Authority has proportionately allocated this loss between bonds refunded through funds released from the debt service accounts and through the issuance of refunding bonds. The loss allocated to the new bonds of $7.0 million was deferred and will be amortized over the life of the new bonds. The portion refunded with cash resulted in immediate recognition of a $0.3 million extraordinary loss in fiscal year 2002.

Subordinate Refunding Bonds

Southern Transmission Project Refunding – In May 2003, the Authority issued $51.75 par value STS 2003 Subordinate Refunding Series A Bonds ("refunding bonds") to refund $58.5 million of STS 1993 Subordinate Refunding Series A Bonds ("refunded bonds"). Funds released from the debt service accounts related to the refunded bonds were $9.8 million. The refunded bonds are expected to be redeemed on July 1, 2003. The refunding is expected to reduce total debt service payments over the life of the refunding issue by approximately $13.3 million and is expected to result in present value savings of approximately $9.9 million based on an average cost of 3.27% on the new bonds.

The refunding bonds are issued as Auction Rate Securities bearing interest at a weekly Auction Rate (0.85% at June 24, 2003) as determined by the Auction Agent. The Authority entered into an interest rate swap agreement to fix the interest rate at 3.266% (see Note 4).

This transaction resulted in a net loss for accounting purposes of $9.8 million, consisting primarily of the write-off of unamortized debt expense, deferred loss on prior refundings and the discount associated with the refunded bonds. The Authority has proportionately allocated this loss between bonds refunded through funds released from the debt service accounts and through the issuance of subordinate refunding bonds. The loss allocated to the new bonds of $8.2 million was deferred and will be amortized over the life of the new bonds. The portion refunded with cash resulted in immediate recognition of a $1.6 million extraordinary loss in fiscal year 2003.

In October 2002, the Authority issued $38.76 million par value STS 2002 Subordinate Refunding Series B Bonds ("refunding bonds") to refund $46.40 million of STS 1992 Subordinate Refunding Series A Bonds ("refunded bonds"). The remaining $5.2 million was funded from debt service accounts related to the refunded bonds and $2.1 million from the General Reserve Fund. The refunding is expected to reduce total debt service payments over the life of the refunding issue by approximately $8.7 million and is expected to result in present value savings of approximately $7.3 million based on an average cost of 4.57% on the new bonds. The refunded bonds were redeemed in December 2002.

This transaction resulted in a net loss for accounting purposes of $5.93 million, consisting primarily of the write-off of unamortized debt expense, deferred loss on prior refundings and the discount associated with the refunded bonds. The Authority has proportionately allocated this loss between bonds refunded through funds released from the debt service accounts and through the issuance of subordinate refunding bonds. The loss allocated to the new bonds of $5.03 million was deferred and will be amortized over the life of the new bonds. The portion refunded with cash resulted in immediate recognition of an $892 thousand extraordinary loss in fiscal year 2003.

In May 2002, the Authority issued $63.9 million par value STS 2002 Subordinate Refunding Series A Bonds ("refunding bonds") to refund $73.3 million of STS 1992 Subordinate Refunding Series A Bonds ("refunded bonds"). The remaining amount of $9.4 million was funded through the release of funds from the debt service accounts related to the refunded bonds. The refunded bonds were redeemed on July 1, 2002. The refunding is expected to reduce total debt service payments over the life of the refunding issue by approximately $4.7 million and is expected to result in present value savings of approximately $3.4 million based on an average cost of 4.97% on the new bonds.

This transaction resulted in a net loss for accounting purposes of $9.7 million, consisting primarily of the write-off of unamortized debt expense, deferred loss on prior refundings and the discount associated with the refunded bonds. The Authority has proportionately allocated this loss between bonds refunded through funds released from the debt service accounts and through the issuance of subordinate refunding bonds. The loss allocated to the new bonds of $8.2 million was deferred and will be amortized over the life of the new bonds. The portion refunded with cash resulted in immediate recognition of a $1.5 million extraordinary loss in fiscal year 2002.

Advance Refundings – In prior years, the Authority established irrevocable escrow trusts with the proceeds from issuance of subordinate refunding bonds. These investments will be used to call specified revenue bonds at scheduled redemption dates.

In February 2003, the Palo Verde 1993 Escrow Funds which were created to defease to maturity $238.3 million of Palo Verde 1993 Refunding Series A and $98.2 million of 1993 Palo Verde Subordinate Refunding Series Bonds, together the "1993 Defeased Bonds," were restructured. The Escrow Securities held to call the 1993 Defeased Bonds were sold and the proceeds were used to purchase securities of the new 1993 Escrow Funds for the purpose of redeeming the 1993 Defeased Bonds on July 1, 2003.

The transaction resulted in a gain of $16.7 million, net of expenses of $580,000. For accounting purposes, this gain is being deferred and amortized as a downward yield adjustment over the life of the debt used to advance refund the 1993 Defeased Bonds. The funds will be used to pay a portion of the 2004 fiscal year capital improvements and the debt service in the amounts of $8.9 million and $7.8 million, respectively.

Prior Year Defeasance of Debt – In prior years, the Authority defeased specified revenue bonds by placing the proceeds from issuance of subordinate refunding bonds in irrevocable trusts to provide for all future debt service payments on the refunded bonds. The trust investments and related liability for defeased bonds are not included in the Authority's financial statements. At June 30, 2003 and 2002, $555.9 million and $790.6 million, respectively, of revenue bonds outstanding are considered defeased.

A summary of changes in long-term debt follows:

	(Amounts in thousands)								
	Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead-Phoenix Project	Mead-Adelanto Project	Multiple Project Fund	San Juan Project	Magnolia Power Project	Total
Total Long-term debt at June 30, 2002	$ 629,554	$ 830,680	$ 20,275	$ 63,720	$ 205,678	$ 222,865	$ 200,675	$ –	$ 2,173,447
Total Debt due within one year at June 30,2002	47,395	26,695	905	–	–	6,600	1,600	–	83,195
Total Debt at June 30, 2002	676,949	857,375	21,180	63,720	205,678	229,465	202,275	–	2,256,642
Principal payments	(47,395)	(26,695)	(905)	–	–	(6,600)	(1,600)	–	(83,195)
Revenue bonds issued	–	–	–	–	–	–	–	314,080	314,080
Bonds refunded	–	(104,895)	–	–	–	–	(70,800)	–	(175,695)
Refunding bonds issued	–	90,505	–	–	–	–	71,850	–	162,355
Decrease in Unamortized debt-related costs, net	28,786	21,099	319	504	1,629	680	7,364	7,650	68,031
Total Debt at June 30, 2003	$ 658,340	$ 837,389	$ 20,594	$ 64,224	$ 207,307	$ 223,545	$ 209,089	$ 321,730	$ 2,542,218
Total Debt due within one year at June 30, 2003	(49,190)	(29,720)	(1,190)	–	–	(7,100)	(8,390)	–	(95,590)
Total Long-term debt at June 30, 2003	$ 609,150	$ 807,669	$ 19,404	$ 64,224	$ 207,307	$ 216,445	$ 200,699	$ 321,730	$ 2,446,628

Unamortized debt-related costs, net are as follows as of June 30,2003 (amounts in thousands):

Unamortized debt-related costs, net:	Loss on Refunding	(Premium) Discount	Total
Palo Verde Project	$ 42,011	$ 61,104	$ 103,115
Southern Transmission System Project	127,141	33,545	160,686
Hoover Uprating Project	3,634	(448)	3,186
Mead-Phoenix Project	5,249	2,441	7,690
Mead-Adelanto Project	14,435	7,434	21,869
Multiple Project Fund	–	11,555	11,555
San Juan Project	11,556	(16,835)	(5,279)
Magnolia Power Project	–	(7,650)	(7,650)
	$ 204,026	$ 91,146	$ 295,172

The scheduled debt service payments for future years ending June 30, are included in the table below. The variable rates used for the PV 1996 Subordinate Refunding Series B and C, and the STS 1996 Subordinate Refunding Series B were the rates at June 30, 2003 of 0.85% and 0.90%, respectively. The variable rates are set by the bond remarketing agent on a weekly basis based on economic conditions and bond ratings. The variable rate used for the SJ 2002 Revenue Refunding Series B was assumed at 4% per annum starting in January 1, 2012.

Fair Value – The fair value of the Authority's long-term debt (including the current portion) is approximately $3.0 billion and $2.6 billion at June 30, 2003 and 2002, respectively. Management has estimated fair value based on the quoted market prices for the same or similar issues or on the current average rates offered to the Authority for debt of approximately the same remaining maturities, net of the effect of a related interest rate swap agreement.

		(Amounts in thousands)								
		Palo Verde Project	Southern Transmission System Project	Hoover Uprating Project	Mead-Phoenix Project	Mead-Adelanto Project	Multiple Project Fund	San Juan Project	Magnolia Power Project	Total
2004	Principal	$ 49,190	$ 29,720	$ 1,190	$ –	$ –	$ 7,100	$ 8,390	$ –	$ 95,590
	Interest	30,799	37,992	1,030	3,889	12,232	14,396	10,398	15,170	125,906
2005	Principal	51,800	28,535	1,230	–	–	7,600	8,805	–	97,970
	Interest	28,426	37,381	987	3,889	12,232	13,864	10,013	15,170	121,962
2006	Principal	–	31,470	1,275	–	–	8,100	9,160	–	50,005
	Interest	28,426	36,844	943	3,889	12,232	13,297	9,631	15,170	120,432
2007	Principal	–	34,230	1,315	3,040	10,135	–	9,570	3,735	62,025
	Interest	28,426	36,279	893	3,748	11,763	13,297	9,186	15,096	118,688
2008	Principal	–	30,950	1,370	3,175	10,600	–	10,050	4,520	60,665
	Interest	28,426	34,668	838	3,598	11,260	13,297	8,695	15,005	115,787
2009-2013	Principal	108,120	185,600	7,715	21,340	62,655	74,900	58,735	24,610	543,675
	Interest	139,885	145,015	3,279	14,617	46,184	50,892	33,304	72,542	505,718
2014-2018	Principal	552,345	254,155	9,685	26,005	84,400	13,800	83,600	30,485	1,054,475
	Interest	108,925	95,674	1,190	7,097	23,778	36,069	10,730	66,056	349,519
2019-2023	Principal	–	333,900	–	18,355	61,385	123,600	15,500	39,100	591,840
	Interest	–	28,788	–	924	3,088	4,454	785	56,997	95,036
2024-2028	Principal	–	69,515	–	–	–	–	–	49,910	119,425
	Interest	–	–	–	–	–	–	–	45,664	45,664
2029-2033	Principal	–	–	–	–	–	–	–	63,695	63,695
	Interest	–	–	–	–	–	–	–	31,186	31,186
2034-2037	Principal	–	–	–	–	–	–	–	98,025	98,025
	Interest	–	–	–	–	–	–	–	10,142	10,142
	Principal	$ 761,455	$ 998,075	$ 23,780	$ 71,915	$ 229,175	$ 235,100	$ 203,810	$ 314,080	$ 2,837,390
	Interest	$ 393,313	$ 452,641	$ 9,160	$ 41,651	$ 132,769	$ 159,566	$ 92,742	$ 358,198	$ 1,640,040
Effective costs of capital		5.52%	4.71%	4.15%	5.57%	5.71%	6.99%	3.98%	4.76%	

6. Net Assets (Deficit)

As a result of the adoption of GASB 34, costs recoverable, deferred credits and funds due to participants were reclassified to net assets (deficit) in accordance with this statement.

Costs Recoverable – Billings to participants are designed to recover "costs" as defined by the power sales and transmission service agreements. The billings are structured to systematically provide for debt service requirements, operating funds and reserves in accordance with these agreements. The difference between billings and the Authority's expenses calculated in accordance with generally accepted accounting principles are deferred as costs recoverable in future periods and are presented as net assets (deficit). It is intended that the deferred amounts will be recovered through billings for repayment of principal on the related bonds.

Deferred Credits – During fiscal year 1990, the Authority issued Multiple Project Revenue Bonds for net proceeds of approximately $600 million to provide funds to finance costs of construction and acquisition of ownership interests or capacity rights in one or more, then unspecified, projects for the generation or transmission of electric energy. Certain of these funds were used to finance the Authority's interests in Mead-Phoenix and Mead-Adelanto. The remaining funds are held in the Multiple Project Fund. Deferred credits represent the accumulated net earnings of the fund.

Funds Due to Participants – In fiscal year 1997, the Authority authorized the creation of a Projects' Stabilization Fund. Deposits may be made into the fund from budget under-runs, after authorization of individual participants, and by direct contributions from the participants. Monies deposited by the participants to this Fund are used to pay for Authority costs as directed by the participants. This fund is not a project-related fund, therefore, it is not governed by any project Indenture of Trust. Funds due to Participants represents the net amount of contributions and net earnings on the invested contributed funds.

Net assets (deficit) are comprised of the following (in thousands):

	(Amounts in thousands)				
	June 30, 2001	Fiscal Year 2002 Activity	June 30, 2002	Fiscal Year 2003 Activity	June 30, 2003
GAAP items not included in billings to participants:					
Depreciation of plant	$ (689,743)	$ (62,318)	$ (752,061)	$ (62,325)	$ (814,386)
Nuclear fuel amortization	(19,548)	–	(19,548)	–	(19,548)
Decommissioning expense	(118,264)	(6,982)	(125,246)	(6,009)	(131,255)
Amortization of bond discount, debt issue costs, and loss on refundings	(508,404)	(40,956)	(549,360)	(35,096)	(548,456)
Interest expense	(64,766)	835	(63,931)	1,654	(62,277)
Bond requirements included in billings to participants:					
Operations and maintenance, net of investment income	144,484	31,091	175,575	99,330	274,905
Costs of acquisition of capacity	17,810	959	18,769	1,153	19,922
Billings to amortize costs recoverable	230,820	50,410	281,230	50,410	331,640
Reduction in debt service billings due to transfer of excess funds	(81,110)	(8,910)	(90,020)	–	(90,020)
Principal repayments	615,579	77,868	693,447	86,871	780,318
Other	50,339	7,457	57,796	7,833	65,629
	(422,803)	49,454	(373,349)	143,821	(229,528)
Multiple Project Fund Net Assets	5,561	794	6,355	337	6,692
Projects' Stabilization Fund Net Assets	200,350	(26,565)	173,785	(77,364)	96,421
	$ (216,892)	$ 23,683	$ (193,209)	$ 66,794	$ (126,415)

7. Commitments and Contingencies

Deregulation – In September 1996, Assembly Bill 1890 (the "Bill") was given final approval. The Bill, which provides for broad deregulation of the power generation industry in California, requires the participation of the state's investor-owned utilities. Consumer-owned utilities can participate on a voluntary basis but must hold public hearings as part of their decision making process. The Bill, which was supported by the Authority, authorizes the collection of a transition charge for generation when a consumer-owned utility opens its service area to competition and participates in the independent transmission system established by the legislation. The Bill also mandates the collection of a public benefit charge from all electric utility customers in the state. Although these funds (approximately 2.85% of gross revenues) must be spent on renewable resources, conservation, research and development, or low income rate subsidies, the governing authority of each consumer-owned utility controls actual expenditures. Due to instability in power open markets in California, in 2001 direct access ceased. The Authority cannot predict the impact of any future direct access or deregulation programs on energy markets or its participants.

Nuclear Spent Fuel and Waste Disposal – Under the Nuclear Waste Policy Act, the Department of Energy ("DOE") was to develop the facilities necessary for the storage and disposal of spent fuel and to have the first such facility in operation by 1998. That facility was to be a permanent repository, but the DOE has announced that such a repository now cannot be completed before 2010. There is ongoing litigation with respect to the DOE's ability to accept spent nuclear fuel; however, no permanent resolution has been reached.

In July 2002, a measure was signed into law designating the Yucca Mountain in the state of Nevada as the nation's high-level nuclear waste repository. This means the DOE can now file a construction and operation plan for Yucca Mountain with the Nuclear Regulatory Commission ("NRC"). The DOE expects that the Yucca Mountain site will be open by 2010, a date which is believed to be highly optimistic. The State of Nevada and its congressional delegation are determined to halt the project through the NRC process or through legal challenges.

Feud over funding of the repository, however, ensues. The Administration and Congressional leaders continue to push for full and adequate funding, in order for the DOE to meet the application deadline of 2004. The Nevada delegation has been working diligently to try to delay the DOE's work on the license application for the Yucca site, in hopes of halting the transfer of nuclear waste to the Nevada facility.

The spent fuel storage in the wet pool at PVNGS exhausted its capacity in 2003. A Dry Cask Storage Facility (also called the Independent Spent Fuel Storage Facility) was built and completed in 2003 at a total cost of $33.9 million (about $2 million for the Authority). In addition to the facility, the costs also account for heavy lift equipment inside the units and at the yard, railroad track, tractors, transporter, transport canister, and surveillance equipment. The facility has the capacity to store all the spent fuel generated by the plant until 2026, the end of its lifetime. To date, five casks, each containing 24 fuel assemblies, from Unit 2 were placed in the Storage Facility. Moving of the spent fuel from Unit 1 to the Storage Facility is in progress. The current plan calls for the removal of between 240 and 288 fuel assemblies from the units to the Storage Facility every year. The costs incurred by the procurement, packing, preparation and transportation of the casks are included as part of the fuel expenses, and would cost approximately $12 million a year (about $700,000 for the Authority). If the permanent repository in Yucca Mountain is opened as scheduled in 2010, the spent fuel from PVNGS will be shipped to the repository starting in 2031.

Nuclear Insurance – The Price-Anderson Act (the "Act") requires that all utilities with nuclear generating facilities share in payment for claims resulting from a nuclear incident. The Act limits liability from third-party claims to approximately $9.5 billion per incident. Participants in the Palo Verde Nuclear Generating Station currently insure potential claims and liability through commercial insurance with a $300 million limit; the remainder of the potential liability is covered by the industry-wide retrospective assessment program provided under the Act. This program limits assessments to $88 million for each licensee for each nuclear incident occurring at any nuclear reactor in the United States; payments under the program are limited to $10 million, per incident, per year. Based on the Authority's 5.91% interest in Palo Verde, the Authority would be responsible for a maximum assessment of $5.2 million, limited to payments of $591,000 per incident, per year.

Other Legal Matters – Claims and a lawsuit for damages have been filed with the Authority, Intermountain Power Authority (the "IPA") and the Department of Water and Power of the City of Los Angeles (the "Department") seeking $100 million in special damages and a like amount in general damages. The claimants allege, among other things, that due to improper grounding of the transmission line of STS, their dairy herds were damaged and the value of their land was diminished. The claimants also seek injunctive relief. The Authority, IPA and the Department intend to vigorously defend the claims.

The Authority is also involved in various other legal actions. In the opinion of management, the outcome of such litigation or claims will not have a material effect on the financial position or the results of operations of the Authority or the respective separate Projects.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
PALO VERDE PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS
REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2003
(Amounts in thousands)

	Debt Service Fund	Debt Service Reserve Fund	Decom-missioning Trust Fund	Deposit Installment	Deposit Reserve Installment	Escrow Account	General Reserve Account	Issue Account	Operating Account	Reserve & Contingency	Revenue Fund	Total
Balance at June 30, 2002	$ 40,636	$ 34,629	$ 103,104	$ 6,161	$ 1,000	$ 571,690	$ –	$ 46,144	$ 25,399	$ 57,973	$ –	$ 886,736
Additions:												
Investment earnings	267	1,418	4,320	14	42	12,345	1	160	557	2,232	6	21,362
Discount on investment purchases	174	59	213	34	1	135,783	53	464	126	1,033	24	137,964
Distribution of investment earnings	(331)	(1,455)	–	(48)	(43)	–	(57)	(614)	(673)	(2,437)	5,658	–
Revenue from power sales	–	–	–	–	–	–	–	–	–	–	191,357	191,357
Distribution of revenue	21,614	–	8,671	–	–	–	122,297	–	35,790	9,096	(196,801)	667
Transfer from escrow fund for principal and interest payments	30,447	–	–	–	–	(39,997)	–	9,550	–	–	–	–
Transfer from escrow restructuring	–	–	–	–	–	(17,291)	7,783	–	580	8,928	–	–
Other	(2,334)	–	–	–	–	50,450	(128,198)	60,574	(2,283)	22,495	–	704
Total	49,837	22	13,204	–	–	141,290	1,879	70,134	34,097	41,347	244	352,054
Deductions:												
Construction expenditures	–	–	–	–	–	–	–	–	–	7,865	–	7,865
Operating expenditures	–	–	3	–	–	–	–	–	29,314	–	–	29,317
Debt issue cost	–	–	–	–	–	3,509	–	–	–	–	–	3,509
Remarketing/Commitment Fees	–	–	–	–	–	–	–	432	–	–	–	432
Fuel costs	–	–	–	–	–	–	–	–	8,131	–	–	8,131
Payment of principal	24,150	–	–	–	–	–	–	23,245	–	–	–	47,395
Interest paid - non-escrow	5,172	–	–	–	–	–	–	29,588	–	–	–	34,760
Premium and interest paid on investment purchases	3	–	–	–	–	–	–	4	–	43	–	50
Payment of principal and interest paid - escrow	30,447	–	–	–	–	–	–	9,550	–	–	–	39,997
Total	59,772	–	3	–	–	3,509	–	62,819	37,445	7,908	–	171,456
Balance at June 30, 2003	$ 30,701	$ 34,651	$ 116,305	$ 6,161	$ 1,000	$ 709,471	$ 1,879	$ 53,459	$ 22,051	$ 91,412	$ 244	$1,067,334

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost for both on balance sheet funds and off balance sheet escrows for legally defeased debt. These balances do not include accrued interest receivable, unrealized gain (loss) on investment, and $96 held in the revolving fund at June 30, 2003 and 2002, respectively.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
SOUTHERN TRANSMISSION SYSTEM PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS
REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2003
(Amounts in thousands)

	Debt Service Fund	Escrow Fund	General Reserve Fund	Issue Fund	Operating Fund	Revenue Fund	Total
Balance at June 30, 2002	$ 12,165	$ 189,875	$ 460	$ 76,809	$ 4,425	$ –	$ 283,734
Additions:							
Investment earnings	59	3,040	4	4,104	43	7	7,257
Discount on investment purchases	36	2,386	1	1,172	25	22	3,642
Distribution of investment earnings	(94)	(1)	(5)	(4,401)	(69)	4,570	–
Revenue from transmission sales	–	–	–	–	–	72,665	72,665
Distribution of revenue	3,501	–	1,565	62,591	9,575	(77,232)	–
Transfer to escrow fund required by refunding bonds issuance	6,545	(163,111)	–	156,566	–	–	–
Bond proceeds	–	100,249	(2,023)	(4,568)	–	–	93,658
Other transfers	–	–	–	–	–	–	–
Total	10,047	(57,437)	(458)	215,464	9,574	32	177,222
Deductions:							
Operating expenses	–	–	–	–	13,475	–	13,475
Debt issue cost	–	–	–	1,605	–	–	1,605
Payment of principal	17,675	–	–	9,020	–	–	26,695
Interest paid	–	–	–	42,149	–	–	42,149
Premium and interest paid on investment purchases	–	2,073	–	–	–	32	2,105
Payment of principal and interest - escrow bonds	–	48,685	–	165,263	–	–	213,948
Total	17,675	50,758		218,037	13,475	32	299,977
Balance at June 30, 2003	$ 4,537	$ 81,680	$ 2	$ 74,236	$ 524	$ –	$ 160,979

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost for both on balance sheet funds and off balance sheet escrows for legally defeased debt. These balances do not include accrued interest receivable, unrealized gain (loss) on investment, and $40 and $38 held in the revolving fund at June 30, 2003 and 2002, respectively.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
HOOVER UPRATING PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS
REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2003
(Amounts in thousands)

	Debt Service Account	Debt Service Reserve Account	Escrow Fund	General Reserve Fund	Advance Payment Fund	Operating Fund	Revenue Fund	Total
Balance at June 30, 2002	$ 1,240	$ –	$ –	$ 1,623	$ 3	$ 1,184	$ –	$ 4,050
Additions:								
Investment earnings	7	–	–	51	–	18	1	77
Discount on investment purchases	8	–	–	19	–	7	–	34
Distribution of investment earnings	(15)	–	–	(70)	–	(25)	110	–
Revenue from power sales	–	–	–	–	–	–	2,289	2,289
Distribution of revenues	1,923	–	–	78	–	399	(2,400)	–
Total	1,923	–	–	78	–	399	–	2,400
Deductions:								
Operating expenses	–	–	–	–	–	261	–	261
Payment of principal	905	–	–	–	–	–	–	905
Interest paid	1,077	–	–	–	–	–	–	1,077
Total	1,982	–	–	–	–	261	–	2,243
Balance at June 30, 2003	$ 1,181	$ –	$ –	$ 1,701	$ 3	$ 1,322	$ –	$ 4,207

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of on balance sheet cash and investments at original cost. These balances do not include accrued interest receivable, unrealized gain (loss) on investment, and $18 and $22 held in the revolving fund at June 30, 2003 and 2002, respectively.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
MEAD-PHOENIX PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS
REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2003
(Amounts in thousands)

	Acquisition Account	Debt Service Account	Debt Service Reserve Account	Operating Fund	Reserve & Contingency Fund	Revenue Fund	Total
Balance at June 30, 2002	$ –	$ 3,387	$ 5,915	$ 169	$ 1,806	$ –	$ 11,277
Additions:							
Investment earnings	–	129	431	1	127	1	689
Distribution of investment earnings	–	431	(435)	–	(127)	131	–
Transmission revenue	–	–	–	–	–	4,179	4,179
Refunds from operating manager	–	–	–	27	–	–	27
Refunds from Arizona Department of Taxation	–	–	–	168	–	–	168
Transfer of revenues	–	3,287	–	840	12	(4,139)	–
Payments from Western Area Power Administration	–	–	–	–	–	100	100
Other transfers	–	168	–	104	–	(272)	–
Total	–	4,015	(4)	1,140	12	–	5,163
Deductions:							
Operating expenses		–	–	1,202	–	–	1,202
Interest paid		3,889	–	–	–	–	3,889
Total	–	3,889	–	1,202	–	–	5,091
Balance at June 30, 2003	$ –	$ 3,513	$ 5,911	$ 107	$ 1,818	$ –	$ 11,349

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of on balance sheet cash and investments at original cost. These balances do not include accrued interest receivable, unrealized gain (loss) on investment, and $12 held in the revolving fund at both June 30, 2003 and 2002.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
MEAD-ADELANTO PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS
REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2003
(Amounts in thousands)

	Acquisition Account	Debt Service Account	Debt Service Reserve Account	Operating Fund	Reserve & Contingency Fund	Revenue Fund	Surplus Fund	Total
Balance at June 30, 2002	$ –	$ 6,850	$ 16,267	$ 389	$ 6,826	$ –	$ –	$ 30,332
Additions:								
Investment earnings	–	132	1,196	2	500	2	–	1,832
Discount on investment earnings	–	25	–	–	–	–	–	25
Distribution of investment earnings	–	1,422	(1,196)	–	(500)	274	–	–
Transmission revenue	–	–	–	–	–	11,407	–	11,407
Distribution of revenues	–	10,787	–	896	–	(11,683)	–	–
Total	–	12,366	–	896	–	–	–	13,264
Deductions:								
Interest paid	–	12,232	–	–	–	–	–	12,232
Operating expenses	–	–	–	1,125	–	–	–	1,125
Total	–	12,232	–	1,125	–	–	–	13,357
Balance at June 30, 2003	$ –	$ 6,984	$ 16,267	$ 162	$ 6,826	$ –	$ –	$ 30,239

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of on balance sheet cash and investments at original cost. These balances do not include accrued interest receivable, unrealized gain (loss) on investment, and $12 held in the revolving fund at June 30, 2003 and 2002, respectively.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
MULTIPLE PROJECT FUND
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS
REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2003
(Amounts in thousands)

	Proceeds Account	Debt Service Account	Earnings Account	Total
Balance at June 30, 2002	$ 246,188	$ 1	$ 1,395	$ 247,584
Additions:				
Investment earnings	17,514	–	50	17,564
Transfer of investment earnings to earnings account	(21,452)	–	21,452	–
Transfer to debt service account	–	21,710	(21,710)	–
Total	(3,938)	21,710	(208)	17,564
Deductions:				
Interest paid	–	15,111	–	15,111
Payment of principal	–	6,600	–	6,600
Total	–	21,711	–	21,711
Balance at June 30, 2003	$ 242,250	$ –	$ 1,187	$ 243,437

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of on balance sheet cash and investments at original cost. These balances do not include accrued interest receivable.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
SAN JUAN PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS
REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2003
(Amounts in thousands)

	Debt Service Account	Debt Service Reserve Account	Escrow Account	Cost of Issuance Fund	Operating Fund	Reserve & Contingency Fund	General Reserve Fund	Revenue Fund	Total
Balance at June 30, 2002	$ 4,148	$ 13,524	$ 124,828	$ 51	$ 3,256	$ 9,342	$ 622	$ –	$ 155,771
Additions:									
Investment earnings	4	1,116	1,845	1	5	98	5	8	3,082
Discount on investments	65	–	33	–	36	85	2	16	237
Distribution of investment earnings	(69)	(1,116)	–	(1)	(41)	(230)	(7)	1,464	–
Revenue from power sales	–	–	–	–	–	–	–	61,123	61,123
Distribution of revenues	11,205	–	–	10	51,762	(366)	–	(62,611)	–
Bond proceeds	–	8,075	71,459	1,216	–	–	–	–	80,750
Transfer from escrow for principal and interest payments	199,050	–	(199,050)	–	–	–	–	–	–
Transfer to escrow funds required by refunding bond issuance	(885)	–	885	–	–	–	–	–	–
Other	–	–	–	(59)	–	–	59	–	–
Total	209,370	8,075	(124,828)	1,167	51,762	(413)	59	–	145,192
Deductions:									
Operating expenses	–	–	–	–	53,811	–	–	–	53,811
Construction expenditures	–	–	–	–	–	290	–	–	290
Debt issue cost	–	–	–	1,218	–	–	–	–	1,218
Payment of principal	1,600	–	–	–	–	–	–	–	1,600
Interest paid – non-escrow	7,485	–	–	–	–	–	–	–	7,485
Payment of principal and interest – escrow	199,050	–	–	–	–	–	–	–	199,050
Total	208,135	–	–	1,218	53,811	290	–	–	263,454
Balance at June 30, 2003	$ 5,383	$ 21,599	$ –	$ –	$ 1,207	$ 8,639	$ 681	$ –	$ 37,509

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of cash and investments at original cost for both on balance sheet funds and off balance sheet escrows for legally defeased debt. These balances do not include accrued interest receivable, unrealized gain (loss) on investment, and $22 and $20 held in the revolving fund at June 30, 2003 and 2002, respectively.

SOUTHERN CALIFORNIA PUBLIC POWER AUTHORITY
MAGNOLIA POWER PROJECT
SUPPLEMENTAL SCHEDULE OF RECEIPTS AND DISBURSEMENTS IN FUNDS
REQUIRED BY THE BOND INDENTURE FOR THE YEAR ENDED JUNE 30, 2003
(Amounts in thousands)

	Debt Service Account	Debt Service Reserve Account	Project Fund	Operating Reserve Fund	Reserve & Contingency Fund	Total
Balance at June 30, 2002	$ –	$ –	$ –	$ –	$ –	$ –
Additions:						
Investment earnings	137	–	62	–	–	199
Bond proceeds	32,918	19,620	255,044	5,000	10,000	322,582
Other	–	–	727	–	–	727
Total	33,055	19,620	255,833	5,000	10,000	323,508
Deductions:						
Construction expenditures	–	–	84,584	–	–	84,584
Debt issue cost	–	–	6,270	–	–	6,270
Premium and interest paid on investment purchases	–	72	–	6	36	114
Total	–	72	90,854	6	36	90,968
Balance at June 30, 2003	$ 33,055	$ 19,548	$ 164,979	$ 4,994	$ 9,964	$ 232,540

This schedule summarizes the receipts and disbursements in funds required under the Bond Indenture and has been prepared from the trust statements. The balances in the funds consist of on balance sheet cash and investments at original cost. These balances do not include accrued interest receivable and unrealized gain (loss) on investment at June 30, 2003.

City of Anaheim

Customers - Retail 109,981
Power Generated and Purchased
(in Megawatt-Hours)
- Self-Generated 1,079,753
- Purchased 2,441,837
- Total 3,521,590

Total Revenues (000s) $280,550*
Operating Costs (000s) $264,258*
*Unaudited

City of Azusa

Customers Served 15,170
Power Generated and Purchased
(in Megawatt-Hours)
- Self-Generated 0
- Purchased 258,320

Sales
- Retail 255,021

Total Revenues (000s) $20,630*
Operating Costs (000s) $24,173*
*Unaudited

City of Banning

Customers Served 10,969
Power Generated and Purchased
(in Megawatt-Hours)
- Self-Generated 0
- Purchased 147,641
- Total 147,641

Total Revenues (000s) $17,159*
Operating Costs (000s) $16,105*
*Unaudited

City of Burbank

Customers Served 51,438
Power Generated and Purchased
(in Megawatt-Hours)
- Self-Generated 77,000
- Purchased 1,090,987
- Total 1,167,987

Total Revenues (000s) $215,435*
Operating Costs (000s) $192,076*
*Unaudited

City of Cerritos

Customers Served ..... To be determined
Power Generated and Purchased
(in Megawatt-Hours)
- Self-Generated 0
- Purchased ..... To be determined

Total Revenues (000s) $0
Operating Costs (000s) $0

City of Colton

Customers Served 17,769
Power Generated and Purchased
(in Megawatt-Hours)
- Self-Generated 0
- Purchased 338,466
- Total 338,466

Total Revenues (000s) $36,142*
Operating Costs (000s) $34,186*
*Unaudited

City of Glendale

Customers Served 83,147
Power Generated and Purchased
(in Megawatt-Hours)
- Self-Generated 166,950
- Purchased 1,322,548
- Total 1,489,498

Total Revenues (000s) $195,648*
Operating Costs (000s) $135,945*
*Unaudited

Imperial Irrigation District

Customers Served 104,678
Power Generated and Purchased
(in Megawatt-Hours)
- Self-Generated 1,044,015
- Purchased 1,985,331
- Total 3,029,346

Total Revenues (000s) $281,906
Operating Costs (000s) $232,265

Los Angeles Department of Water and Power

Customers Served 1,420,814
Power Generated and Purchased
(in Megawatt-Hours)
- Self-Generated 12,935,821
- Purchased 14,751,367
- Total 27,687,188

Total Revenues (000s) $2,140,752*
Operating Costs (000s) $1,974,501*
*Unaudited

City of Pasadena

Customers Served 59,075
Power Generated and Purchased
(in Megawatt-Hours)
- Self-Generated 161,979
- Purchased 1,157,817
- Total 1,319,796

Total Revenues (000s) $142,721
Operating Costs (000s) $127,131

City of Riverside

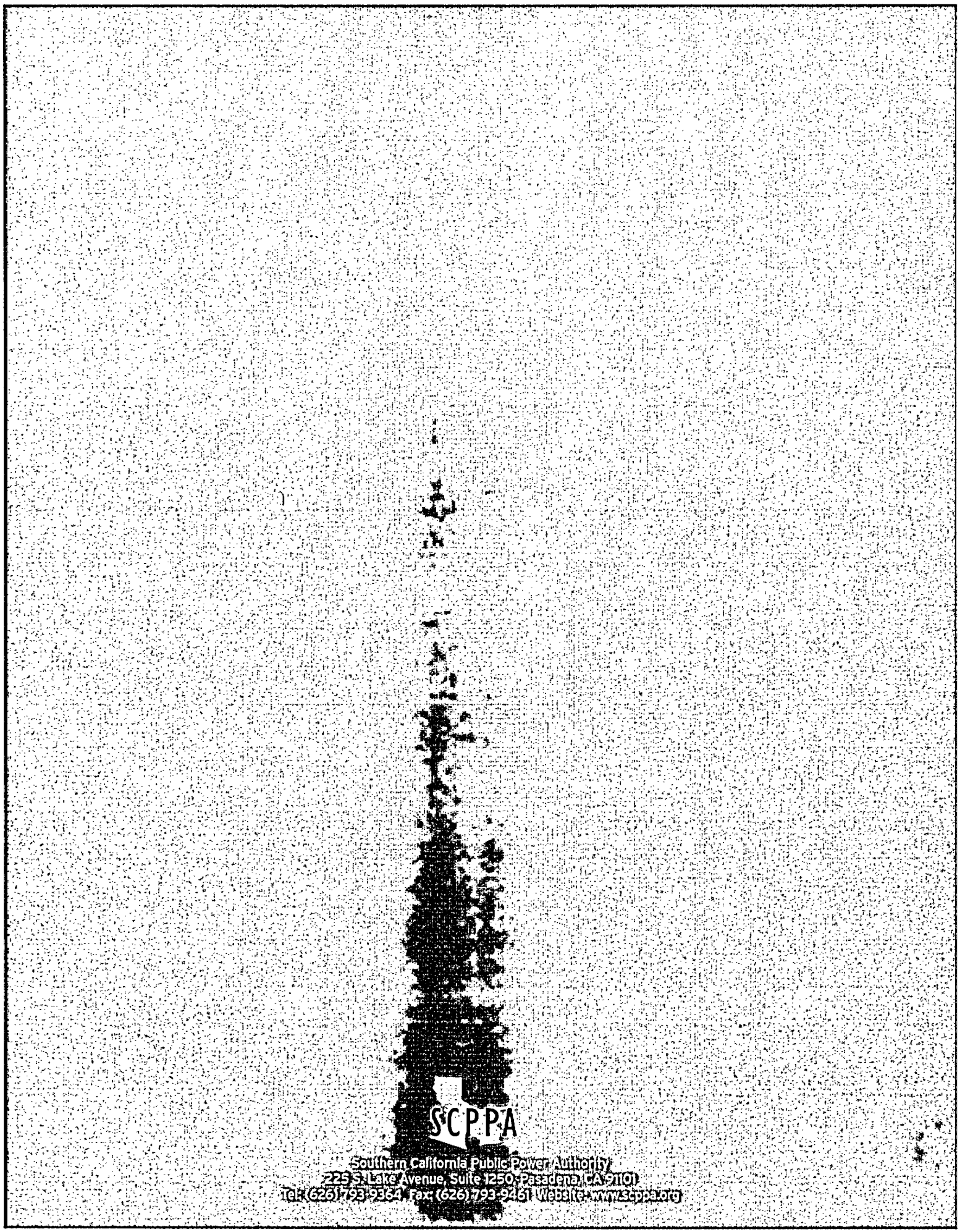
Customers Served 98,459
Power Generated and Purchased
(in Megawatt-Hours)
- Self-Generated 331,600
- Purchased 2,014,600
- Total 2,346,200

Total Revenues (000s) $203,101*
Operating Costs (000s) $189,100*
*Unaudited

City of Vernon

Customers Served 2,059
Power Generated and Purchased
(in Megawatt-Hours)
- Self-Generated 350
- Purchased 1,315,686
- Total 1,316,036

Total Revenues (000s) $101,393
Operating Costs (000s) $87,530



Southern California Public Power Authority
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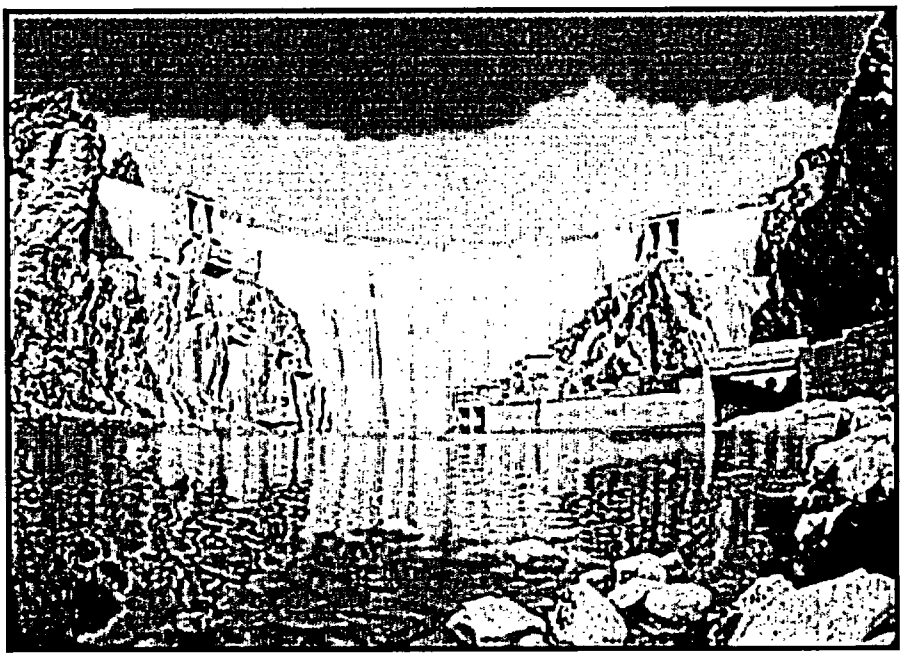
Salt River Project 2003 Annual Report



LIVING THE LEGACY

CENTENNIAL SRP 1903-2003

SRP is two entities: the Salt River Project Agricultural Improvement and Power District, and the Salt River Valley Water Users' Association. Both are based in Tempe, Ariz.

The District, a public power system, provides electricity to nearly 800,000 customers, representing about 1.8 million people in Maricopa, Gila and Pinal counties in central Arizona. The District is an integrated utility, providing generation, transmission and distribution services.

The Association, a private corporation, manages a system that delivers about 1 million acre-feet of water annually to agricultural, urban and municipal water users in the greater Phoenix metropolitan area.

CENTENNIAL SRP 1903-2003

On the cover: Theodore Roosevelt Dam is the cornerstone of SRP water operations and a contributor to SRP's hydrogeneration supply.

From wild desert to tamed metropolis, the Salt River Valley has been dramatically transformed over the past century. And for those 100 years, SRP has helped the communities of the Valley grow and prosper with reliable, affordable energy and water services.

A LETTER TO OUR CUSTOMERS, BONDHOLDERS AND SHAREHOLDERS

For SRP, fiscal year 2003 was extraordinary. Celebrating a century of service, after all, only happens once in a hundred years! Our centennial year was full of special recognitions, public programs, community contributions, and more.

The year brought its share of new business challenges. Our water business was strained by an extended drought. A weakened local economy, while more robust than in many other areas, affected our customers and ultimately our sales and revenues.

We are pleased to report that despite a slow start, the year ended with modest yet respectable net revenues of nearly $46.7 million. A rebound in the wholesale energy market helped us end on this positive note. Our total operating revenues were nearly $2 billion, down slightly from $2.2 billion the previous year. Through aggressive cost-cutting measures and reduced expenditures for wholesale energy, SRP reported total operating expenses of $1.8 billion for the year, compared with $2.1 billion in fiscal year 2002.

Our efforts to reduce debt continued this year, and are reflected in our debt ratio of 56.0 percent, which has improved steadily over the past two decades. Funds available – internally generated cash from operations after expenses and debt service – were $261.1 million. We consider this performance admirable given the financial challenges we faced throughout the fiscal year. We continue to hold bond ratings of AA and Aa2 from S&P and Moody's, which are terrific in this day and age.

SRP now has nearly 800,000 electric customers, the third-largest public power utility in the U.S. in terms of customers served. SRP's electric service area stretches 2,900 square miles across Central Arizona, and our energy supports the demands of a metropolis that is one of the nation's largest and most appealing urban centers. This beautiful Salt River Valley is home to nearly 3.5 million people and offers a quality of life surpassed by none other. Our electric customer growth continues at a steady pace, about 3 percent, which mirrors the population growth in the Valley.

As the Valley's primary water steward, serving a 388-square-mile area, SRP continues to manage surface and groundwater supplies for municipal systems, agricultural purposes and various other water users. This past year we met many new opportunities involving our water business. The relationship between power and water is at the heart of SRP's unique status, and we are passionate about our water management responsibilities.

SRP is honored to be a recipient of the 2003 Business Ethics Award from the Better Business Bureau of Central/Northern Arizona. The award recognizes organizations that demonstrate high standards of business ethics and conduct, both in operations and in business relationships with employees, vendors and customers.

SRP's emphasis on service, low prices, community commitment and the public's involvement in our business practices are clear benefits of public power and a legacy that will resonate in future years.

We also continue a century-long commitment to the communities we serve. We consider community involvement an important responsibility: SRP's nonprofit contributions and in-kind services topped $3 million during the year and our employees again demonstrated their commitment by volunteering in record numbers.

We could not reach our goals without the assistance of others. We work in cooperation with many — electric customers, water shareholders, competitors, regulators and policy makers. Our practice is to reach consensus on how SRP conducts business, and we are confident in a system that protects and provides for the Valley's promising future. As always, the skills and dedication of our employees create a workplace where tremendous results are possible.

Adequate, affordable power and water services, and community support, are the foundation of SRP's legacy. We will remain committed to this legacy as the future unfolds while embracing the challenges ahead.

William P. Schrader
President

John M. Williams Jr.
Vice President

A MESSAGE FROM THE GENERAL MANAGER

This has been a year of contrasts. We celebrated SRP's Centennial, but experienced continued drought and a wholesale electric market that escapes logic. Defying a poor economy, SRP enjoyed steady growth in residential electric customers, but saw industrial and commercial usage fall. For the first time in 20 years, our retail kilowatt-hour sales did not increase from the previous year. And, we have a new, three-year contract with IBEW Local Union 266.

Through what can be called heroic efforts by our employees, SRP's financial results are on budget, a testament to the dedicated men and women who have been committed to making the year successful.

The irony of the drought situation is not lost on those familiar with our history. A seven-year drought 100 years ago laid the predicate for creation of the Salt River federal reclamation project. Today, in addition to storage facilities on the Salt and Verde rivers, and groundwater, we are relying on supplemental water supplied by the Central Arizona Project, so we are concerned with the possibility of an extended drought on the Colorado River watershed as well.

A further irony arising from the current drought is the resultant impact on habitat for the endangered Southwest Willow Flycatcher. The bird species has been found in the foliage that has grown in the areas of SRP's largest reservoir, Roosevelt Lake, as the level of the lake has dropped. During fiscal 2003, we received a permit from the U.S. Fish & Wildlife Service, which permits re-filling the lake when runoff again occurs in sufficient quantities. This permit requires SRP to offset the impact of filling the reservoir.

Of particular concern is whether we are in a long-term dry period. Unfortunately, only time will tell. With the tremendous growth we have seen in the last half-century, 77 percent of our water is delivered for urban use, further complicating the consequences of a long-term dry period in the West.

Turmoil in the wholesale electric market continues. FERC, the Federal Energy Regulatory Commission, struggles with formulating a stable, nationwide competitive wholesale marketplace, while Congress continues to debate national energy policy. At this juncture, neither we nor anyone else knows what the outcome will be, but SRP has invested substantial effort and resources to emerge from this turmoil able to continue to provide low-cost, reliable electric service to our customers.

The rhetoric we have heard the last few years from the investor-owned community continues as FERC attempts to fashion national wholesale markets through the establishment of regional transmission organizations subject to a standard market design. We have tried to be supportive, and participate, while pointing out the importance of regional differences and the financial impracticality of a "one size fits all" approach. We have concluded, however, there are incremental improvements that are less costly for the West, but still provide a substantial share of the benefits of efficient wholesale markets.

We noted last year that volatility in the wholesale market had directed our attention to enhanced ability to manage financial risks inherent in electricity and natural gas transactions. We have continued to improve our analytical capability, strengthen our procedures, and implement new strategies to mitigate risk as our industry undergoes significant credit deterioration.

SRP continues to believe public power has a place in the competitive wholesale market, and can contribute and be productive, while remaining subject to a different level of regulation. Retail competition, we believe, must wait for proof that as wholesale market rules emerge, they do in fact work. The Arizona Corporation Commission, which regulates investor-owned utilities, and the state Legislature, which establishes parameters for public power entities, continue their re-examination, begun last year, of retail electric competition.

Of continuing concern is the outcome at FERC of reallocation of capacity on the natural gas pipeline used to deliver fuel to SRP plants that serve our retail customers. We are concerned with the outcome, as well as reliability of service, as we watch the world situation and the proliferation of new power plants that receive fuel from the pipeline.

This year, SRP began construction of new generation and completed major transmission additions, as we prepare for continued growth. We are developing additional generation and transmission, and intend to be well prepared for customer growth as our service territory prospers. We are in good condition to meet the needs of summer 2003.

For the third time in four years, SRP received the J.D. Power and Associates award for outstanding residential customer satisfaction. We continue to invest in our customer operations to ensure that they are efficient and provide the highest levels of service. We have increased participation in our existing programs and continue to develop a number of new, innovative programs. These include M-Power®, the largest prepayment program for electric service in the nation; Spanish-language bills; and ever-expanding Web functionality.

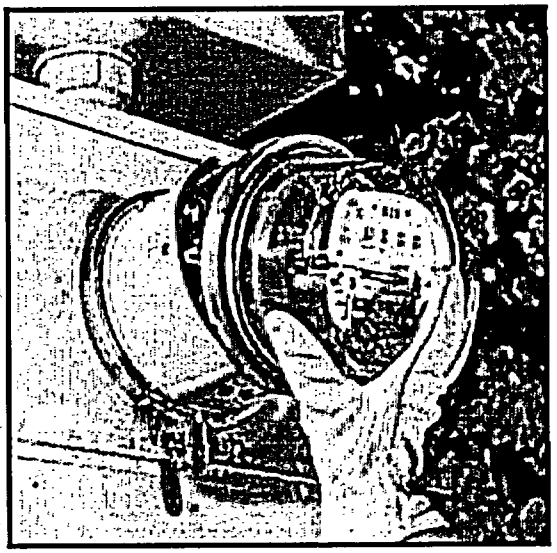
All in all, it was a challenging and productive year. We celebrated a significant milestone, worked hard, participated as our industry dealt with turmoil, and ended the year on a sound financial basis. Our commitment to the communities we serve remains a fixture in our strategy for success. Finally, thanks to our elected officials, without whose support SRP could not thrive.

Richard H. Silverman
General Manager

PROVIDING

ENERGY

THAT POWERS THE VALLEY



Salt River Project 2003 Annual Report

The power picture for SRP today reflects experience and careful planning. Electric customers can be assured that SRP is well positioned to provide the high-value service they have come to expect.

During the year, SRP completed a new 250-megawatt (MW) plant at the Kyrene Generating Station in Tempe, to serve the fast-growing Southeast Valley. This natural-gas-fired facility provides a clean, reliable source of generation. SRP also began construction on another Southeast Valley plant. When the first unit of that plant is commercially operational in 2005, it will provide 550 MW of electricity for local customers.

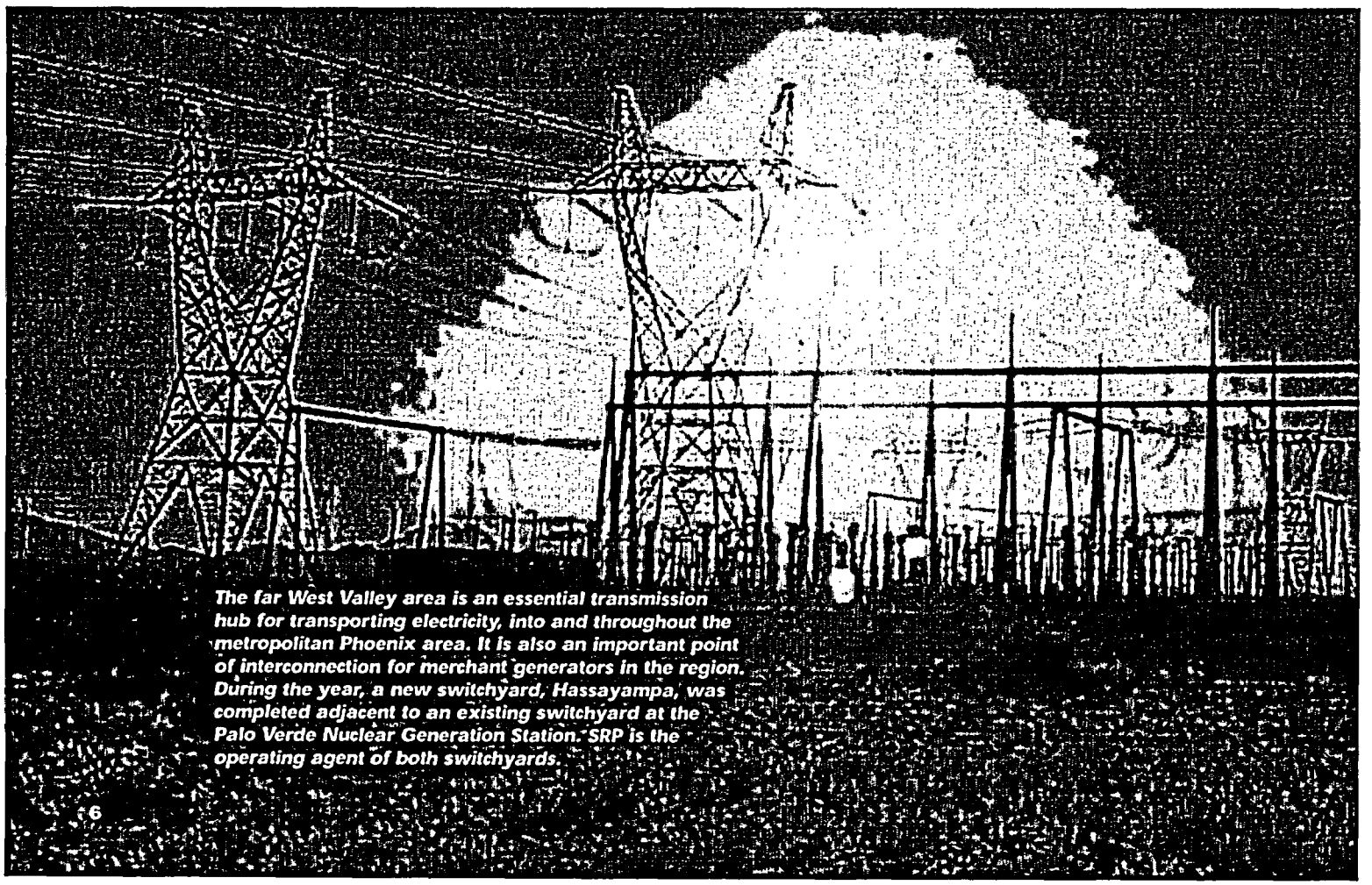
With the new facilities, an additional 800 MW will be available to serve SRP customers, bringing total resource capacity to 7,009 MW, including power purchases. This year, due to dry conditions that limited hydrogeneration and a surplus in the wholesale market, SRP's energy portfolio was 3 percent hydro/renewable; 5 percent natural gas/oil; 42 percent fossil fuel; and 14 percent nuclear. Nearly 36 percent of the resources to serve SRP customers last year were purchased on the then-favorable wholesale market through spot purchases and contracts. Expenses for those purchases declined from the previous year due to lower prices in that market.

Continued maintenance and improvements to plant facilities that SRP owns, participates in and/or manages are vital to producing reliable results at generating stations. This year, at Navajo Generating Station (NGS) near Page, Ariz., a $34 million overhaul of the 750-MW Unit 3 resulted in increased operational efficiencies, improved equipment reliability and reduced emissions. SRP owns 21.7 percent of NGS and paid $7.5 million of the overhaul costs. Similar work on Units 1 and 2 is planned for the next two years.

NGS, one of northern Arizona's largest employers, was recognized last year by Platts *Power* magazine for having one of the lowest sulfur dioxide emission rates among power plants in the nation. To quote the magazine, "Navajo, located in a majestic part of the West, has three 750-MW supercritical units working almost flat out while maintaining a leadership position in emissions control. It produced 17,386 gigawatt hours in 2001, fifth-most among coal-fired power plants, and operated at 88 percent capacity factor, good for 13th place in that category."

At the 3,810-MW Palo Verde Nuclear Generating Station west of the Valley, preliminary construction continued for the replacement of two steam generators later this year in Unit 2 at an estimated total cost of $210 million. Replacements for the other two units are planned over the next five years at this generating facility, a major Southwest generation source and transmission hub. SRP holds a 17.49 percent ownership position in Palo Verde and will contribute $37 million for the upgrades.

Other plant improvement projects included a $119 million



The far West Valley area is an essential transmission hub for transporting electricity, into and throughout the metropolitan Phoenix area. It is also an important point of interconnection for merchant generators in the region. During the year, a new switchyard, Hassayampa, was completed adjacent to an existing switchyard at the Palo Verde Nuclear Generation Station. SRP is the operating agent of both switchyards.

emissions control upgrade at the Craig Generating Station in Colorado, and another $18 million total in improvements to three other facilities.

Plant performance was exceptional in many cases. The SRP owned and operated Coronado Generation Station in northeast Arizona achieved an equivalent availability of 97 percent and an equally impressive forced outage rate of just 1.9 percent. Our Valley-based peaking facility, Agua Fria Generating Station, recorded a near-perfect starting reliability of 99.8 percent.

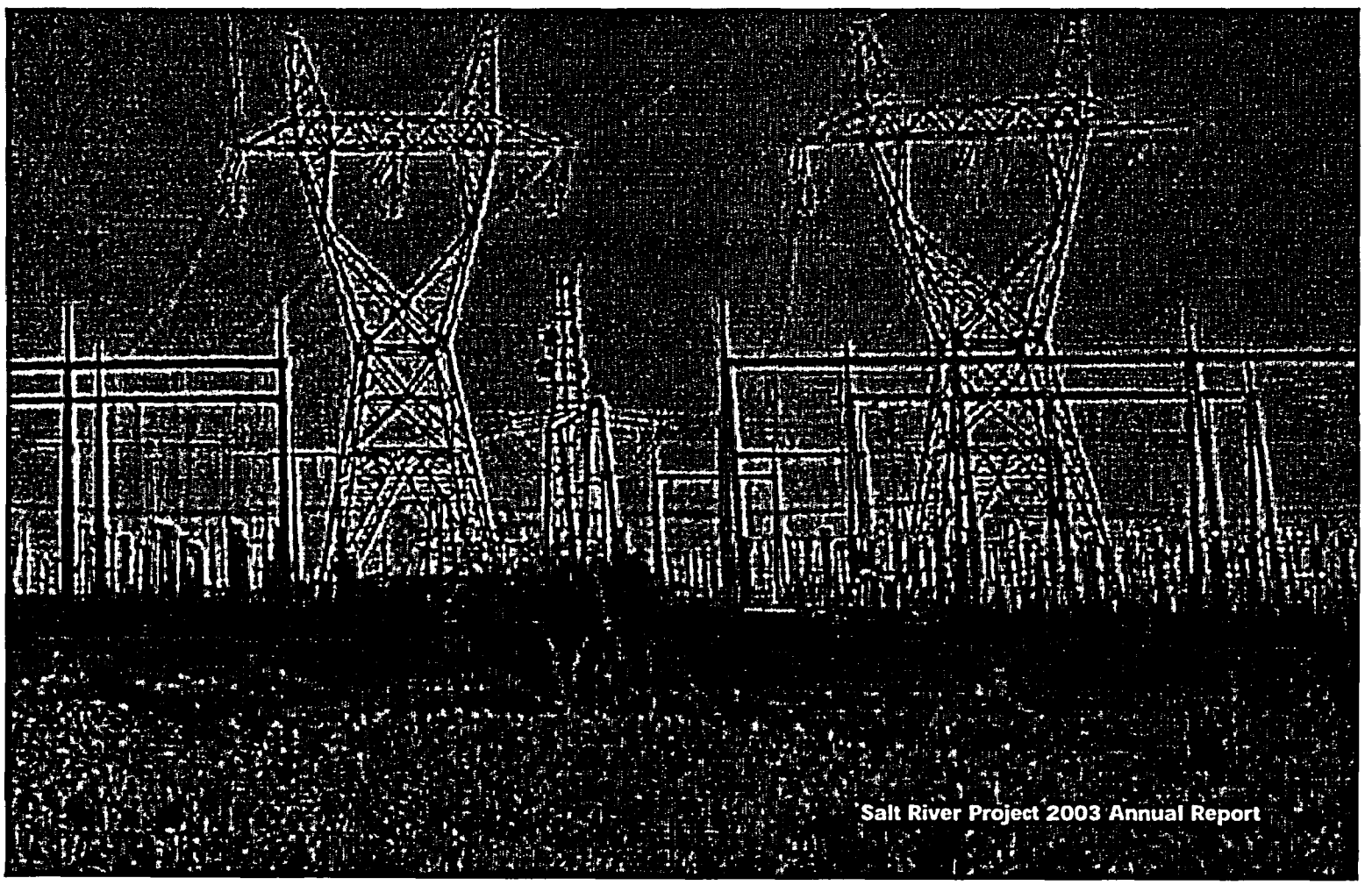
Other new plants near the Valley, mostly developed in the last two years by merchant generators, are increasing the supply of available electricity. While just three years ago the reserve margin for the West was 23 percent, by next year these plants plus other provider-developed facilities will increase that margin to nearly 40 percent. SRP continues with plans for additional resources as growth projections lessen the surplus later in this decade.

Transmission projects also proceed at record pace, enabling more of this new generation to reach Valley customers. While the Palo Verde Nuclear Generating Station is managed and operated by APS, the associated switchyard and transmission system is operated and managed by SRP. In addition to serving the nuclear generating station, the Palo Verde Switchyard is a major hub or clearinghouse for trading and transferring electricity throughout Arizona, California and the Southwest.

As operating agent of the Palo Verde Transmission System and the recently completed Hassayampa Switchyard, SRP handled the interconnection of five new merchant generators that plan to operate a total of 5,800 MW of gas-fired, combined-cycle generation. SRP, as part of a commitment to open system access and low energy prices, developed the necessary technical study work, contracts and operating procedures to permit these generators to operate, and continues to coordinate the numerous transactions this energy market demands.

Over the past two years, SRP has been working with APS on the Southwest Valley Project, a new major transmission line to serve the metropolitan Phoenix area. The project consists of a 36-mile 500 kilovolt (kV) transmission line from Palo Verde to a new transmission substation located in the Southwest Valley area. The Rudd Substation is named for the late Eldon Rudd, a former U.S. Congressman and SRP Board of Directors member.

SRP also installed a 230kV capacitor bank at the Kyrene Substation in the Southeast Valley to provide voltage support during heavy summer loads. This effort, along with the Southwest Valley Project, significantly increases the amount of energy SRP can import to the Valley. Future plans include the siting and permitting of a 150-mile 500kV line from Palo Verde to SRP's service area in northern Pinal County. This project is known as the Southeast Valley Project and construction is planned for the



last half of the decade.

SRP continues to be involved with other transmission owners and market participants in the desert Southwest and Rocky Mountain areas in efforts to form the WestConnect regional transmission organization (RTO). We also are participating in regional work groups that are addressing issues between the three RTOs being formed in the Western interconnection — WestConnect, RTO West and the California Independent System Operator. Work groups are making progress on issues of Western interconnection transmission planning, congestion management and market monitoring.

Distribution services continued to undergo improvements for increased reliability, especially in underground cable replacement. Over the past eight years, SRP has replaced nearly 8 million feet of primary distribution cable, and will continue with another 1 million feet this year. That will bring new cable replacement to about 25 percent of SRP's 40 million feet existing. The next scheduled replacement is secondary distribution cable, which serves homes and neighborhood lighting. While disruptions in service are inevitable in the distribution segment of the business, especially weather-related interruptions, SRP consistently ranks high among utilities for its short outage times and low outage occurrences.

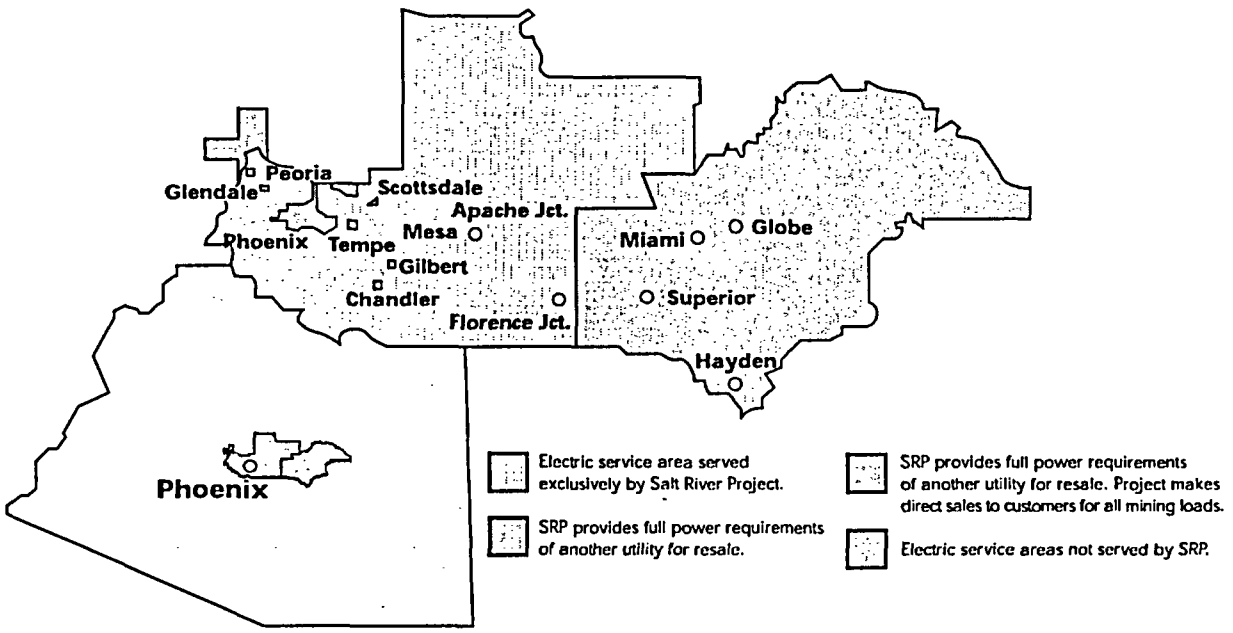
SRP places high value on meter-reading services. Zero-error standards boost customer satisfaction and SRP efficiency. With meter readers responsible for as many as 100,000 reads each per year, performance is consistently high, with a near-perfect record for many meter readers.

As a summer-peaking utility, SRP for many years has made efforts to balance the summer-winter load relationships through seasonal price differentials. Customers pay less for electricity in the lower-demand winter months and more in the higher-demand summer months due to increased production costs. Combined with SRP's operating efficiency practices, electric customers enjoy exceptional value for their energy dollar. The prices paid by our residential and commercial customers are among the lowest in the Southwest.

SRP's portfolio of clean energy offerings continues to expand. Our EarthWise Energy™ program is a mix of renewable energy sources including solar, landfill gas and hydrogeneration. In addition, wind, solar water heating, and woodchip technologies are being explored as new options. About 3,500 SRP residential and commercial customers voluntarily support this program by paying a small premium on their monthly electric bills.

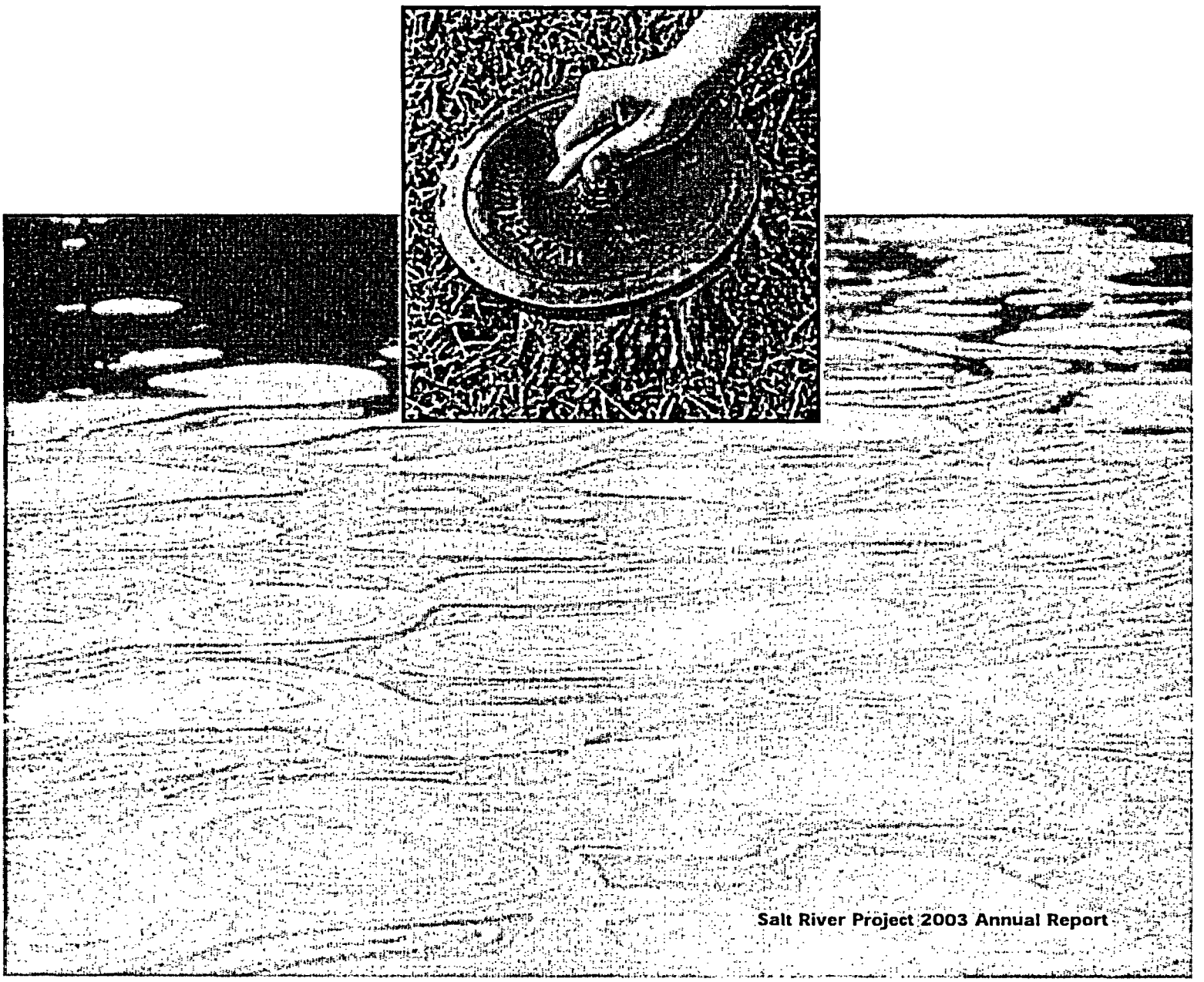
SRP again was recognized for high quality service to electric customers, which we associated with our well-trained and talented employees who consistently demonstrate their commitment to customers. During the year, SRP ranked as one of the top electric utilities in the West and in the nation in a satisfaction survey of midsize business customers. SRP also has been the top utility in overall residential customer satisfaction in the West for three of the past four years, according to J.D. Power and Associates.

SRP'S ELECTRIC SERVICE AREA



The SRP Agricultural Improvement and Power District provides electricity to power users in a 2,900-square-mile service area in parts of Maricopa, Gila and Pinal counties.

MANAGING WATER FOR TODAY AND THE FUTURE



Salt River Project 2003 Annual Report

A record-setting drought was the dominant issue for our water business this year, challenging SRP, the state's water management, and future supplies.

The numbers are telling: Seven of the last eight years have brought below-average snowfall and runoff on the watersheds of the Salt and Verde rivers. Winter 2002 was the driest winter season on record. In fact, the current drought is approaching the severity of the extended drought at the turn of the 20th century, which led to the formation of SRP and the construction of Theodore Roosevelt Dam. If not for a wet winter in 1998, the current drought would be more severe in terms of runoff produced and duration.

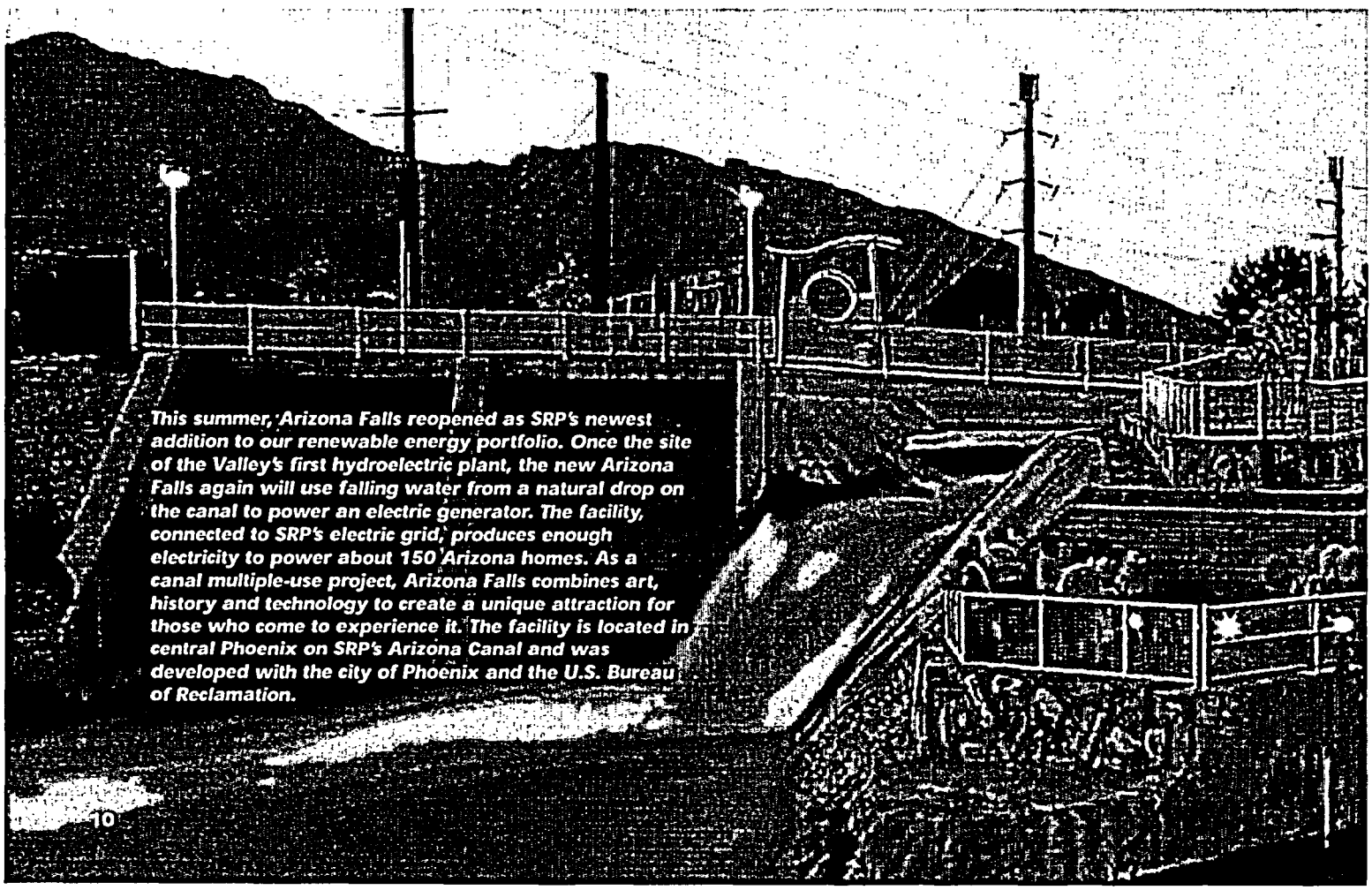
The drought affects not only Arizona but also the entire Southwestern United States, and has brought together water providers, users and agencies to develop shared remedies to ensure future water supplies. These remedies include surface water management, water exchanges and banking, conservation and efficiency enhancements.

SRP is participating in a state drought task force to develop a short-term response plan, a long-term adaptive management plan and a statewide conservation program. The U.S. Department of Interior is proposing a plan for the West that emphasizes water savings and encourages cooperation among all leaders, with decisions maintained at the local level. In response, several Valley cities have implemented drought management plans. For example, City of Phoenix departments are required to reduce water consumption by 5 percent, and residential and business consumers are being called upon to step up their conservation efforts.

SRP is the largest water supplier to the Valley, serving a water territory stretching about 388 square miles across the center of the state. The Salt and Verde river watersheds, about 13,000-square-miles across north central Arizona, normally provide about two-thirds of SRP's water supply.

Due to the persistently dry conditions, SRP in January 2003 reduced water allocations by 33 percent to balance supply with demand. If this allocation reduction holds for the entire year, which appears likely, it will mark the first time since 1951 that SRP shareholders have endured an entire year of reduced allocations. SRP specialists are consulting with agricultural and municipal users to help them manage water consumption and address the reductions.

Continued below-normal precipitation in the SRP watersheds means surface water supplies continue to be



This summer, Arizona Falls reopened as SRP's newest addition to our renewable energy portfolio. Once the site of the Valley's first hydroelectric plant, the new Arizona Falls again will use falling water from a natural drop on the canal to power an electric generator. The facility, connected to SRP's electric grid, produces enough electricity to power about 150 Arizona homes. As a canal multiple-use project, Arizona Falls combines art, history and technology to create a unique attraction for those who come to experience it. The facility is located in central Phoenix on SRP's Arizona Canal and was developed with the city of Phoenix and the U.S. Bureau of Reclamation.

below normal as well. To responsibly manage existing surface water, SRP is increasing the use of groundwater. In fact, under today's conditions, our groundwater supply has never been more important.

For the first time in recent history, as much as 45 percent of SRP's deliveries this year will come from groundwater.

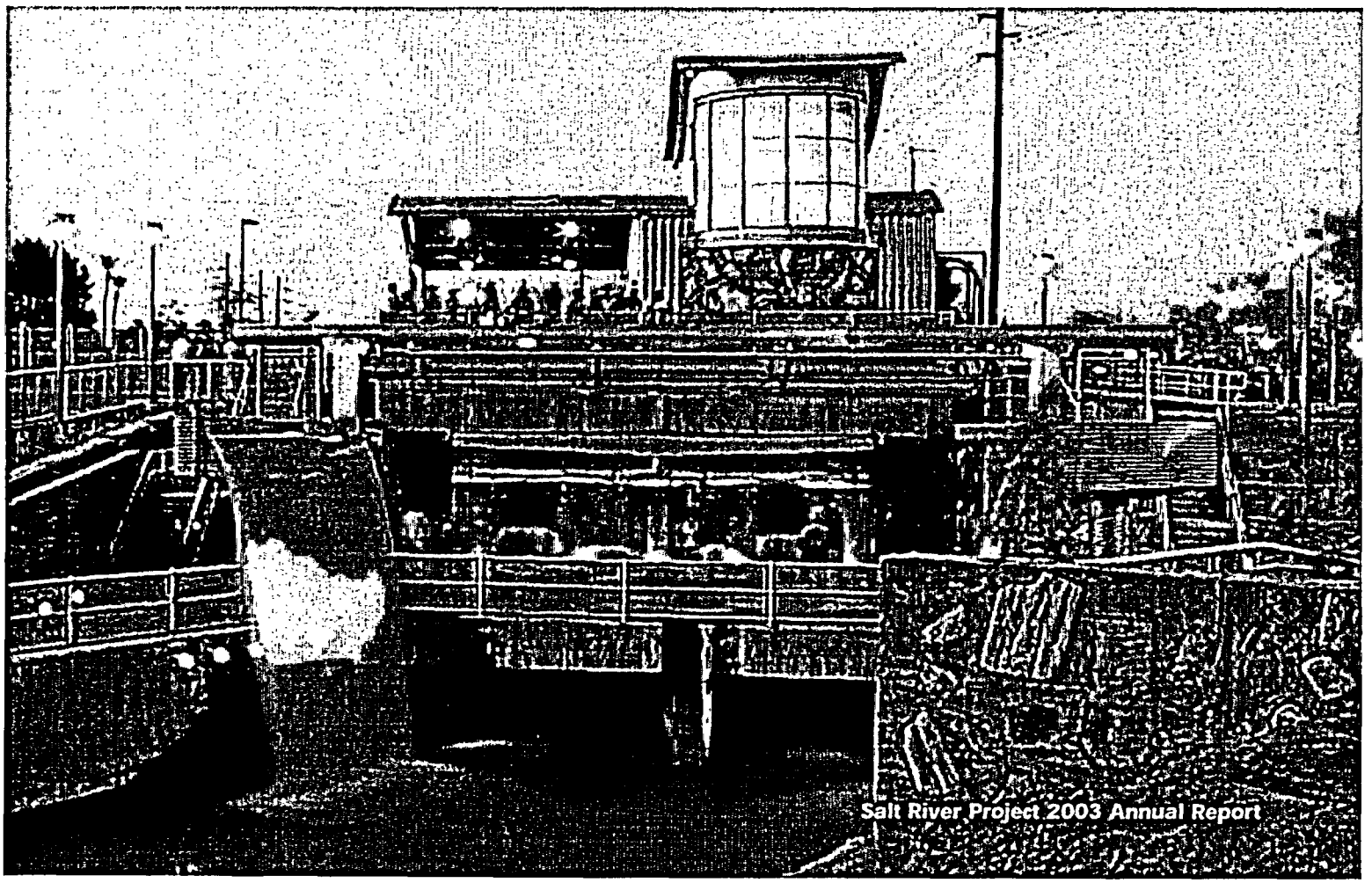
SRP maintains 250 deep wells, many of which have been in existence for half a century. Extraordinary demands upon our groundwater facilities mean diligent testing and tracking of well pumps and equipment performance. As well, SRP uses state-of-the-art techniques to monitor and evaluate the condition of vital well components. Such innovative tools are used in our efforts to manage these increasingly important facilities.

Always mindful of our role as water steward, we are stepping up our public role in water conservation, developing outreach communications and conducting educational public events to encourage water-use efficiencies. Many efforts are coordinated with local municipalities to leverage resources and reach more consumers. SRP emphasizes water consumption behaviors such as urban irrigation management and landscaping techniques that minimize water use.

To support long-term water requirements, SRP continues to maintain the surface and groundwater rights for the Valley, which is the foundation of our water legacy. Two significant water-rights disputes were settled during the year. The first, with the Zuni Indian Tribe, resolves the Tribe's claim to waters from the Little Colorado River Basin and enables SRP to continue to operate the wells that serve the Coronado Generating Station. In exchange, the Tribe will receive federal and state funds to purchase water rights for the Zuni Heaven Reservation in Arizona.

The second settlement, which involves several water users including SRP and the Gila River Indian Community, resolves a 15-year-old dispute regarding waters from the Gila River Basin, which includes the Verde and Salt river watersheds. Under the agreement, SRP will provide a predetermined allocation to the Tribe, and in return, the Tribe waives all claims to water from the Gila River Basin. The agreement preserves a significant share of the Valley's water supply.

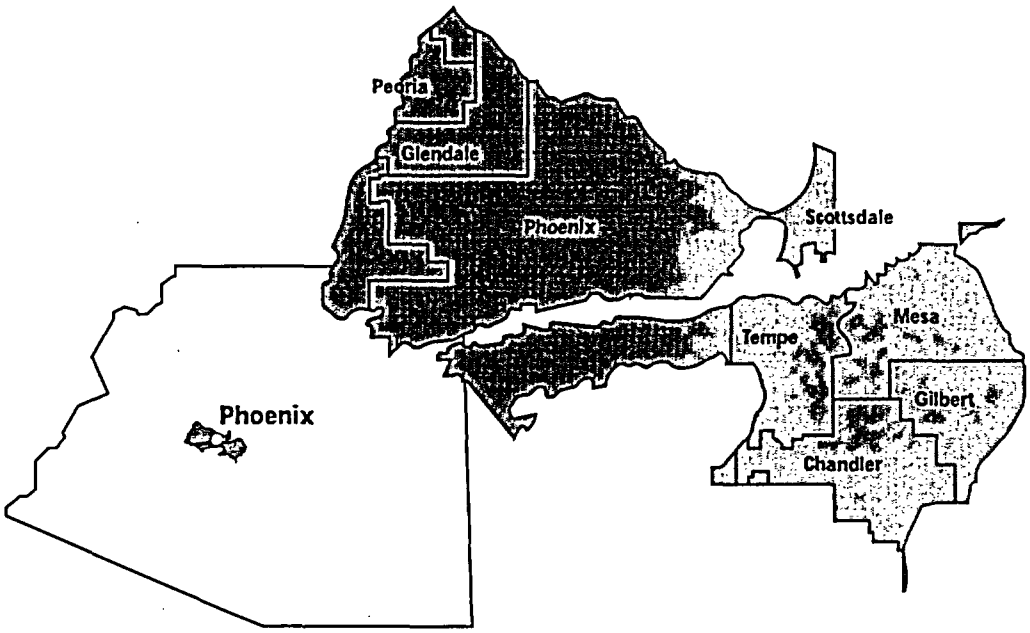
SRP continues to evaluate and pursue opportunities for new sources of water business revenues, to help underwrite water costs to shareholders, cities and other consumers. A new SRP offering along the continued theme of conservation addresses the ongoing



conversion of land to urban use from agricultural. Cities, homeowner associations and businesses that use water for turf and plants are the target of this educational program. In addition, SRP is supporting a new water recharge project west of the Valley, in La Paz County, with technical operations that provide water measurement and accounting for the private facility.

The status of the water supply that SRP manages depends upon the weather. Some foresee a prolonged dry spell for the state. While no one can predict nature, SRP and the communities we serve continue to commit the investments needed to ensure a long-term water supply. Should the drought continue or worsen, opportunities on the horizon include increased use of reclaimed water where possible, additional water banking, and expanded conservation efforts.

SRP'S WATER SERVICE AREA

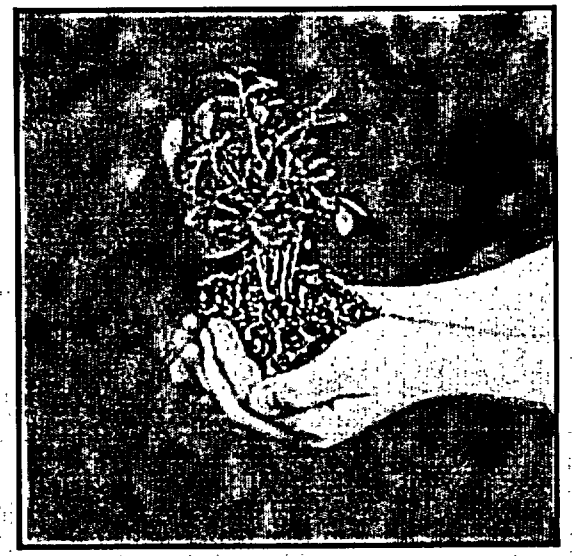


The Salt River Valley Water Users' Association administers water rights in a 248,239-acre area in central Arizona.

SUPPORTING

COMMUNITIES

IS OUR RESPONSIBILITY



SRP's legacy of supporting the communities we serve is as much a part of our mission as the supply of power and water.

As we entered our centennial year in mid-2002, we initiated several special activities to emphasize SRP's historic partnership with local communities and our commitment to their future.

Developed in concert with the Library of Congress, the Arizona Heritage Project awarded $15,000 in grants for schools to research and create projects illustrating the vibrant history and folklore of Arizona communities. One example is a charter school in the Southeast Valley community of Chandler. Students there will research, document and help preserve the unique Yaqui culture of Guadalupe, Ariz.

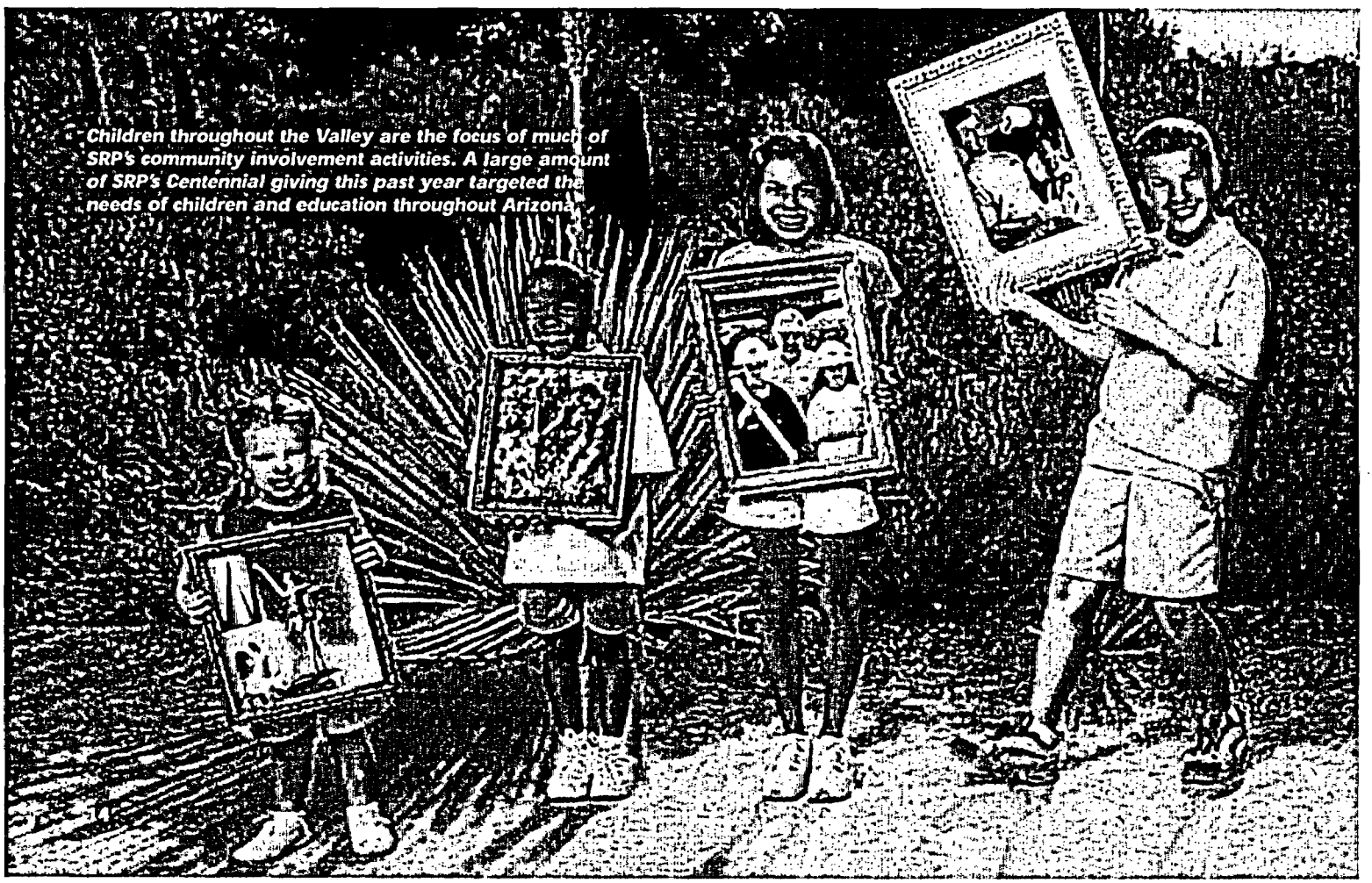
Linking the development of SRP with the growth of Central Arizona, SRP partnered with the Phoenix Museum of History to launch a special exhibit entitled *SRP: The Power of Water*. Through an array of artifacts, interactive exhibits and video demonstrations, thousands of visitors are discovering the vital role of water and power in the Valley's history and future.

SRP's involvement with special segments of our communities was demonstrated through title sponsorships of key non-profit events spanning the Valley. These included Valle del Sol's *Profiles of Success* luncheon featuring Hispanic community leadership; the Environmental Excellence Awards, sponsored by Valley Forward, an organization of environmentally-sensitive businesses; and the West Valley Fine Arts Council's Diamond Ball, supporting cultural opportunities throughout the West Valley.

Focusing on the future, SRP also collaborated with East Valley Partnership to host *Growing Livable Communities* – a forum in which local visionaries and corporate leaders gathered to exchange ideas and insights critical to the long-term well-being and development of the Valley.

A special grant program was developed to build upon SRP's strong history of community involvement and to help our employees move their volunteer commitment to a new level. Following a call for employee proposals, SRP awarded $55,000 to six employee teams who collaborated with community organizations to accomplish projects that permanently enhanced the organizations in a meaningful way. One such award was a $10,000 grant to renovate the on-site medical facility at the Child Crisis Center of the East Valley in Mesa, a shelter for abused and neglected children. Fifteen SRP employees gave their own time over several weeks to complete the project.

In Page, Ariz., the owners of the SRP-operated Navajo Generating Station dedicated $225,000 to the Coconino Community College Foundation for the new technology



Children throughout the Valley are the focus of much of SRP's community involvement activities. A large amount of SRP's Centennial giving this past year targeted the needs of children and education throughout Arizona.

wing at the Lake Powell campus. The wing, named in honor of the Navajo Generating Station for its significance to Northern Arizona, will support two distance-learning classrooms and a computer lab – and the high-tech aspirations of students in Page and surrounding communities.

One goal of SRP's cultural outreach efforts is to promote understanding of indigenous arts and culture, and activities that are unique to local communities. A $200,000 contribution to the Heard Museum in Phoenix this past year will help renew an exhibit, *Native Peoples of the Southwest*, and support the museum's annual fair and market.

Continuing a tradition of commitment to education enrichment, SRP once again assisted public and private non-profit schools with special programs and projects. SRP awarded Project RESOURCE grants worth nearly $40,000 this year to 11 schools around the state. Examples of programs that will benefit from these grants include an expansion of the phonics books library at a West Valley elementary school, and the purchase of a projector for hearing impaired students at a Phoenix-based school for the deaf. Once again, SRP served as a major corporate sponsor of the Arizona Academic Decathlon, a series of events to broaden and challenge high school students' academic abilities.

During the year, SRP provided $3.3 million to charitable organizations through employee donations and corporate contributions, which benefited a broad range of initiatives in education, health and human services, environmental, civic and the arts.

Collectively, SRP employees, retirees and family members averaged more than 703,000 hours in volunteer service to local schools, civic organizations, non-profit groups and environmental efforts. More than 85 percent of the SRP workforce donated their time, talents and financial support to non-profit activities benefiting hundreds of community-based organizations and activities.

These extraordinary efforts earned several major recognitions during the year, including the highest volunteer honor in Arizona, the *Governor's Volunteer Service Award*. SRP also received the American Public Power Association's *Community Service Award*, and an award for *Excellence in Corporate Volunteerism* from the Volunteer Center of Maricopa County/*The Business Journal*.

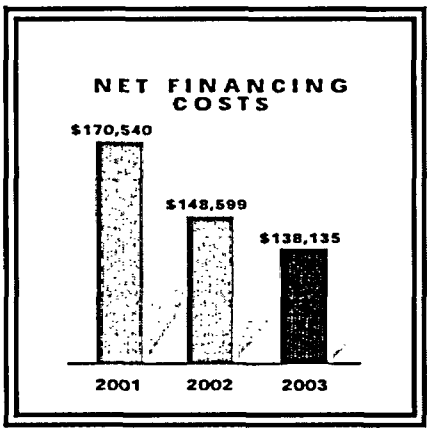
Creating a clear and compelling link between community involvement and corporate goals, engaging in thoughtful corporate giving, and empowering our employee volunteers – these are the driving forces behind SRP's legacy of service.

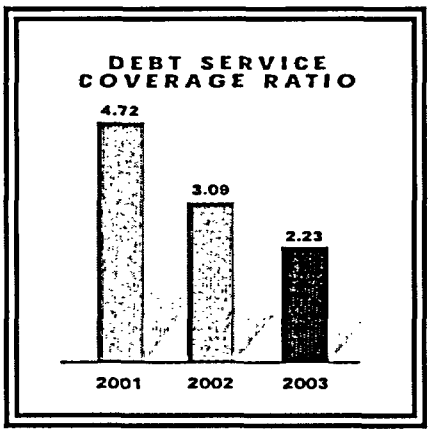
Providing energy and water services that support the vitality of the Valley, as well as community programs to help improve lives, are the foundation of SRP's legacy. We are committed to this legacy as the future unfolds.

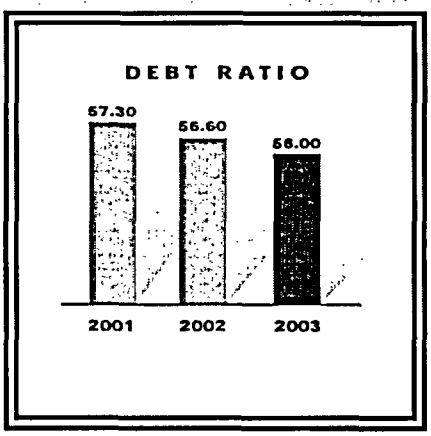
SRP

FINANCIAL

INFORMATION







MANAGEMENT'S FINANCIAL AND OPERATIONAL SUMMARY

This section explains the general financial condition and results of operations for SRP. SRP includes the Salt River Project Agricultural Improvement and Power District (the District), its subsidiaries, and the Salt River Valley Water Users' Association. The results of these entities are combined for financial reporting purposes.

Overview of Business

The District owns and operates an electric system which generates, purchases, and distributes electric power and energy, and provides electric service to residential, commercial, industrial and agricultural power users in a 2,900-square-mile service territory spanning portions of Maricopa, Gila and Pinal counties, plus mining loads in an adjacent 2,400-square-mile area in Gila and Pinal counties.

The District remains a vertically integrated organization. It is developing additional generation, transmission and distribution resources to keep pace with load growth. The District pursues both short-term and long-term purchases, refinements to its conservation programs, building its own generation, and acquiring existing generation resources.

For example, the District currently is in negotiations for the development of the Springerville Generating Station Expansion located in Springerville, Ariz. SRP will contract for 100 megawatts (MW) of output from that plant. Additionally, the District will have development rights to build an additional 400-MW coal-fired unit in the future on the same site. This development is subject to numerous conditions and no assurance can be given that such conditions will be satisfied.

SRP manages a system of dams and reservoirs, and has responsibility for the construction, maintenance and operation of a supply system to deliver raw water for irrigation and municipal treatment purposes. It provides the water supply for an area of approximately 248,200 acres located within the major portions of the cities of Phoenix, Avondale, Glendale, Mesa, Tempe, Chandler, Gilbert, Peoria, Scottsdale and Tolleson.

In 1997, the District established a wholly owned, taxable subsidiary, New West Energy Corporation (New West Energy), to market, at retail, energy available to the District that was surplus to the needs of its retail customers, and energy that might have been rendered surplus by retail competition in Arizona in the supply of generation. However, because of the turmoil in the California energy market, New West Energy has discontinued marketing excess energy, although it may resume this activity in the future. It continues to provide energy-related services to various customers within and outside the state of Arizona. New West Energy has reduced its staff and now is supporting the District's energy services activities in Arizona.

The District's other subsidiary, Papago Park Center, Inc., manages a mixed-use commercial development known as Papago Park Center located on land owned by the District adjacent to its administrative offices. The District accumulated this land over a number of years for its use. The District's long-range plan includes the private development of portions of Papago Park Center.

Results of Operations

SRP's net revenues for the fiscal year ended April 30, 2003, were $46.7 million compared to $19.8 million for the previous year. Operating revenues were $2.0 billion for fiscal year 2003, compared to $2.2 billion for fiscal year 2002. The revenue decline this past year was principally due to depressed prices in the wholesale electricity market, though weather and general economic conditions were factors.

Some specific factors were:

- Severely depressed wholesale market prices resulted in a wholesale revenue decrease of $232.0 million from the prior year.
- The economic downturn had a moderate affect on certain retail customers, but in aggregate, retail sales were only $1.0 million less than the prior year.
- Weather conditions from October through April were the most mild in the last 10 years.

Operating expenses were $1.8 billion for fiscal year 2003, compared with $2.1 billion for fiscal year 2002. Some of the major variances from last year were:

- During the year, SRP proactively took steps to reduce budgeted operating and maintenance costs, re-examined its capital program, curtailed business travel, limited new-hires, and found lower-cost ways of accomplishing regular business activities in order to help offset weaknesses in the wholesale market.
- Purchased power expense was 45 percent lower than the prior year as the energy market was affected by excess supply, and there was adequate generation by SRP's resources to cover our retail load requirements.
- Fuel expense decreased due to positive hedging and price mitigation strategies.
- As a result of our continued emphasis on refinancing and debt reduction, financing costs decreased by 7 percent from the prior year.

In water operations, delivery revenues were $12.4 million compared to $14.3 million the previous year, due to continuing drought conditions. Water-related operating expenses were 6 percent higher than the prior year due to increased operations and maintenance expenses.

Accounting Issues

Effective May 1, 2001, the District adopted Statement of Financial Accounting Standards (SFAS) No. 133, *"Accounting for Derivative Instruments and Hedging Activities"* as amended. SFAS No. 133 requires that entities recognize all derivatives as either assets or liabilities in the balance sheet and measure those instruments at fair value. Changes in the fair value of derivative financial instruments are either recognized periodically in net revenues or accumulated net revenues. For a detailed explanation of the effects of SFAS No. 133 on the District's financial results, see Note 3 in the accompanying notes to the combined financial statements.

Notes 10 and 12 in the accompanying notes to the combined financial statements address the continuation of operations at Mohave Generating Station (Mohave) in which the District has an ownership interest. The District and the other Participants in Mohave entered into a settlement with the Sierra Club that requires the installation of pollution abatement equipment by the end of 2005 if the plant will continue to be operated with coal. In addition, the initial term of the coal supply agreement serving Mohave expires at the end of 2005 and the Hopi Tribe has demanded that pumping water for the slurry pipeline serving Mohave cease by the end of 2005. The Mohave Participants, in turn, have refused to commit to install pollution abatement equipment without reasonable assurance that water will be available to deliver coal to the plant. Due to the lead-time required to order and install the pollution abatement equipment, the plant likely will cease operations at the end of 2005 for some period of time. The District and the other Mohave Participants are negotiating with various parties, including the Hopi Tribe, to extend the life of Mohave beyond 2005. The District's management is committed to this effort. If necessary, the District believes it will be able to replace the energy from other sources.

Energy Risk Management Program

The District's mission to serve its retail customers is the cornerstone of its risk management approach. This means that the District builds or acquires resources to serve retail customers, not the wholesale market. However, as a summer-peaking utility, there are times of the year when the District's resources and/or reserves are in excess of its retail load, thus giving rise to some wholesale activity. The District has an Energy Risk Management Program to limit exposure to risks inherent in normal retail and wholesale energy business operations by measuring and minimizing exposure to price risks, credit risks, and operating risks. To meet the goals of the Energy Risk Management Program, the District uses various physical and financial instruments, including forward contracts, futures, swaps, and options. Certain of these transactions are accounted for under SFAS No. 133. For a detailed explanation of the effects of SFAS No. 133 on the District's financial results, see Note 3 in the accompanying notes to the combined financial statements.

The Energy Risk Management Program is managed according to a policy approved by the District's Board, and overseen by a "Risk Oversight Committee." The policy covers areas such as strategies, specific price and control risk issues, and the credit policy that the District applies to its wholesale counter-parties. The Risk Oversight Committee is composed of senior executives. The District maintains an "Energy Risk Management Department," separate from the energy marketing area, that regularly reports to the Risk Oversight Committee. In addition, the District has established a credit reserve for its activity in wholesale markets. The District believes that its existing risk management structure is appropriate and that any exposures are adequately covered by existing reserves.

Electric Pricing

The District has a diversified customer base, and no single retail customer provides more than 1.6 percent of its operating revenues. The District has implemented projects and programs geared towards enhancing customer loyalty by offering customers a range of pricing and service options. Moreover, the District has reduced retail prices and is one of the low price leaders in the Southwest.

The District is a summer-peaking utility and for many years has made an effort to balance the summer-winter load relationships through seasonal price differentials. In addition, the District prices on a time-of-day basis for large commercial and industrial, and certain residential and small commercial users.

On November 26, 2001, the District's Board approved a Fuel and Purchase Power Adjustment Mechanism that became effective May 1, 2002. On October 17, 2002, the Board approved an adjustment pursuant to the Fuel and Purchase Power Adjustment Mechanism effective November 1, 2002. The adjustment charge is a direct pass-through of expenses and resulted in an average annual increase in retail customer bills of 2.8 percent.

Recapitalization Plan

During fiscal year 2003, the District completed a refinancing plan to improve its operating efficiency and financing flexibility (the Recapitalization Plan) so that it is better positioned to remain competitive and to respond to future changes.

As part of the Recapitalization Plan transactions during fiscal year 2003, the District issued its $570.0 million Electric System Revenue Bonds, 2002 Series B; its $202.4 million Salt River Project Electric System Refunding Revenue Bonds, 2002 Series C; and its $104.1 million Salt River Project Electric System Refunding Revenue Bonds, 2002 Series D on September 26, 2002, and November 8, 2002. The District also defeased with cash $408.0 million of its outstanding Revenue Bonds, on August 14, 2002. The aggregate financial benefits of the total Recapitalization Plan are close to $80.0 million in present value savings.

The goals of the Recapitalization Plan are: (1) to accelerate debt retirement by the District of its Revenue Bonds; (2) to provide the District with increased financing and operating flexibility in the future; (3) to adopt a modern and more flexible bond resolution; and (4) to recognize Debt Service savings.

Capital

The Capital Improvement Program is driven by the need to expand the generation, transmission and distribution systems of the District to meet growing customer electricity needs and to maintain a satisfactory level of service reliability. Of the total Capital Improvement Program, more than 25 percent of the funds are directed to generation projects. These include the expansion of the Santan Generating Station in the southeast portion of the District's service territory and the installation of steam generators at the Palo Verde Nuclear Generating Station. Another 38 percent of the funds are planned for expansion of the electrical distribution system to meet new growth and to replace aging underground cable. The addition of new 69 kilovolt transmission facilities and the construction of a new high-voltage transmission line account for an additional 4 percent of the funds.

The District pays a portion of the cost for its Capital Improvement Program from internally generated funds and a portion from the proceeds of Revenue Bonds.

Code of Conduct

In accordance with the requirements of the 1998 Arizona Electric Power Competition Act, the District developed and implemented a Code of Conduct (the Code). The underlying principles of the Code are to protect the public interest and provide all competitors a fair opportunity to compete in the electric generation and other competitive services markets. Effective January 1, 2001, the District amended the Code to more closely isolate the distribution functions and services provided by the District and to simplify the Code.

The District is subject to an annual independent audit of adherence to the Code. The audit covering calendar year 2002 was completed in June 2003. The audit report confirmed the District has complied in all material respects with the Code's requirements.

COMBINED BALANCE SHEETS

As of April 30, 2003 and 2002 (Thousands)

ASSETS	2003	2002
UTILITY PLANT		
Plant in service –		
Electric	$ 6,927,360	$ 6,652,164
Irrigation	242,156	246,974
Common	403,752	385,897
Total plant in service	7,573,268	7,285,035
Less – Accumulated depreciation on plant in service	(3,536,026)	(3,313,051)
	4,037,242	3,971,984
Plant held for future use	20,399	31,144
Construction work in progress	556,217	482,568
Nuclear fuel, net	41,692	42,966
	4,655,550	4,528,662
OTHER PROPERTY AND INVESTMENTS		
Non-utility property and other investments	96,556	110,166
Segregated funds, net of current portion	516,205	368,296
	612,761	478,462
CURRENT ASSETS		
Cash and cash equivalents	397,641	594,523
Temporary investments	57,925	185,463
Current portion of segregated funds	137,767	81,044
Receivables, net of allowance for doubtful accounts	168,970	140,843
Fuel stocks	35,281	35,612
Materials and supplies	65,087	70,063
Other current assets	39,530	14,964
	902,201	1,122,512
DEFERRED CHARGES AND OTHER ASSETS	466,873	458,291
	$ 6,637,385	$ 6,587,927

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

COMBINED BALANCE SHEETS

As of April 30, 2003 and 2002 (Thousands)

CAPITALIZATION AND LIABILITIES	2003	2002
LONG-TERM DEBT	$ 2,809,581	$ 3,033,931
ACCUMULATED NET REVENUES AND OTHER COMPREHENSIVE INCOME	2,203,928	2,302,090
TOTAL CAPITALIZATION	5,013,509	5,336,021
CURRENT LIABILITIES		
Current portion of long-term debt	260,428	114,340
Accounts payable	142,621	121,727
Accrued taxes and tax equivalents	64,174	57,821
Accrued interest	54,398	40,981
Customers' deposits	40,157	26,645
Other current liabilities	147,741	117,706
	709,519	479,220
DEFERRED CREDITS AND OTHER NON-CURRENT LIABILITIES	914,357	772,686
COMMITMENTS AND CONTINGENCIES (Notes 5, 7, 8, 9, 10, 11 and 12)		
	$ 6,637,385	$ 6,587,927

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

COMBINED STATEMENTS OF NET REVENUES & COMPREHENSIVE INCOME (LOSS)

For the years ended of April 30, 2003 and 2002 (Thousands)

	2003	2002
OPERATING REVENUES	$ 1,993,925	$ 2,214,378
OPERATING EXPENSES		
Power purchased	394,017	713,797
Fuel used in electric generation	395,683	420,070
Other operating expenses	362,123	338,176
Maintenance	151,834	139,908
Depreciation and amortization	435,815	411,915
Taxes and tax equivalents	90,388	86,255
Total operating expenses	1,829,860	2,110,121
Net operating revenues	164,065	104,257
OTHER INCOME (EXPENSES)		
Interest income	29,192	55,801
Other expenses, net	(1,725)	(3,497)
Total other income (expenses), net	27,467	52,304
Net revenues before financing costs	191,532	156,561
FINANCING COSTS		
Interest on bonds	139,844	137,544
Capitalized interest	(16,770)	(14,398)
Amortization of bond discount/premium and issuance expenses	(6,511)	1,732
Interest on other obligations	21,572	23,721
Net financing costs	138,135	148,599
NET REVENUES BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	53,397	7,962
CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	(6,728)	11,834
NET REVENUES	46,669	19,796
OTHER COMPREHENSIVE INCOME (LOSS)	(144,831)	515
COMPREHENSIVE INCOME (LOSS)	$ (98,162)	$ $20,311

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

COMBINED STATEMENTS OF CASH FLOWS

For the years ended of April 30, 2003 and 2002 (Thousands)

	2003	2002
CASH FLOWS FROM OPERATING ACTIVITIES		
Net revenues	$ 46,669	$ 19,796
Adjustments to reconcile net revenues to net cash provided by operating activities:		
Depreciation and amortization	435,815	411,915
Post-retirement benefits expense	36,900	27,900
Amortization of provision for loss on long-term contracts	(13,281)	(13,281)
Amortization of net bond discount/premium and issuance expenses	(6,511)	1,732
Amortization of spent nuclear fuel storage	1,562	1,446
Cumulative effect of change in accounting principle	(6,728)	11,834
Other, net	233	-
Decrease (increase) in -		
Fuel stocks and materials & supplies	5,307	(19,695)
Receivables, including unbilled revenues, net	(28,127)	207,464
Other assets	(23,811)	(96,188)
Increase (decrease) in -		
Accounts payable	20,894	(85,402)
Accrued taxes and tax equivalents	6,353	26,270
Accrued interest	13,417	(11,298)
Other liabilities, net	10,568	105,286
Net cash provided by operating activities	499,260	587,779
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to utility plant, net	(512,887)	(643,564)
Purchases of securities	(135,773)	(361,077)
Sales and maturities of securities	282,311	502,645
Net cash used for investing activities	(366,349)	(501,996)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from issuance of long-term debt	876,450	1,013,150
Retirement of commercial paper	(150,000)	-
Repayment of long-term debt, including refundings	(843,490)	(1,097,470)
Payment of capital lease obligation	(25,334)	(15,371)
Increase in segregated funds	(187,419)	(28,523)
Net cash used for financing activities	(329,793)	(128,214)
NET DECREASE IN CASH AND CASH EQUIVALENTS	(196,882)	(42,431)
BALANCE AT BEGINNING OF YEAR IN CASH AND CASH EQUIVALENTS	594,523	636,954
BALANCE AT END OF YEAR IN CASH AND CASH EQUIVALENTS	$ 397,641	$ 594,523
SUPPLEMENTAL INFORMATION		
Cash Paid for Interest (Net of capitalized interest)	$ 131,229	$ 158,165
Non-cash Financing Activities		
Utility plant acquired under capital lease	$ -	$ 292,068
Loss on defeasance	$ 45,289	$ 60,646

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

NOTES TO COMBINED FINANCIAL STATEMENTS
April 30, 2003 and 2002

1. Basis of Presentation:

The Company – The Salt River Project Agricultural Improvement and Power District (the District) is an agricultural improvement district organized in 1937 under the laws of the State of Arizona. It operates the Salt River Project (the Project), a federal reclamation project, under contracts with the Salt River Valley Water Users' Association (the Association) by which it has assumed the obligations of the Association to the United States of America for the care, operation and maintenance of the Project. The District owns and operates an electric system that generates, purchases and distributes electric power and energy, and provides electric service to residential, commercial, industrial and agricultural power users in a 2,900-square-mile service territory in parts of Maricopa, Gila and Pinal Counties, plus mine loads in an adjacent 2,400-square-mile area in Gila and Pinal Counties. The Association, incorporated under the laws of the Territory of Arizona in 1903, operates an irrigation system as the agent of the District.

In 1997, the District established a wholly-owned, taxable subsidiary, New West Energy Corporation (New West Energy), to market, at retail, energy available to the District that was surplus to the needs of its retail customers, and energy that might have been rendered surplus by retail competition in Arizona in the supply of generation. However, as a result of the turmoil in the California energy market, New West Energy has discontinued marketing excess energy, although it may resume this activity in the future. It continues to provide energy-related services to various customers within and outside the State of Arizona.

Possession and Use of Utility Plant – The United States of America retains a paramount right or claim in the Project that arises from the original construction and operation of certain of the Project's electric and water facilities as a federal reclamation project. Rights to the possession and use of, and to all revenues produced by, these facilities are evidenced by contractual arrangements with the United States of America.

Principles of Combination – The accompanying combined financial statements reflect the combined accounts of the Association and the District (together referred to as SRP). The District's financial statements are consolidated with its two wholly-owned taxable subsidiaries, New West Energy and Papago Park Center, Inc. (PPC). PPC is a real estate management company. All material inter-company transactions and balances have been eliminated.

Regulation and Pricing Policies – Under Arizona law, the District's publicly-elected Board of Directors (the Board) has the authority to establish electric prices. The District is required to follow certain procedures, including public notice requirements and special Board meetings, before implementing changes in standard electric price schedules.

2. Significant Accounting Policies:

Basis of Accounting – The accompanying combined financial statements are presented in conformity with accounting principles generally accepted in the United States of America (GAAP) and reflect the pricing policies of the Board. The District's "regulated" operations apply Statement of Financial Accounting Standards No. 71, "*Accounting for the Effects of Certain Types of Regulation*" (SFAS No. 71), while "non-regulated" operations follow GAAP for enterprises in general. Classification of regulated and non-regulated operations is determined in accordance with applicable GAAP accounting guidelines.

The preparation of financial statements in compliance with GAAP requires management to make estimates and assumptions that affect the reported amounts in the financial statements and disclosures of contingencies. Actual results could differ from the estimates.

Utility Plant – Utility plant is stated at the historical cost of construction, less any impairment losses. Capitalized construction costs include labor, materials, services purchased under contract, and allocations of indirect charges for engineering, supervision, transportation and administrative expenses and capitalized interest or an allowance for funds used during construction (AFUDC). AFUDC is the estimated cost of funds used to finance regulated plant additions

and is recovered in prices through depreciation expense over the useful life of the related asset. The cost of property that is replaced, removed or abandoned, together with removal costs, less salvage, is charged to accumulated depreciation.

Composite rates of 4.70% and 5.45% were used in fiscal years 2003 and 2002 to calculate interest on funds used to finance construction work in progress, resulting in $16.8 million and $14.4 million of interest capitalized, respectively.

Depreciation expense is computed on the straight-line basis over the estimated useful lives of the various classes of plant assets. The following table reflects the District's average depreciation rates on the average cost of depreciable assets, for the fiscal years ended April 30:

	2003	*2002*
Average electric depreciation rate	3.99%	3.92%
Average irrigation depreciation rate	2.68%	2.88%
Average common depreciation rate	5.18%	6.41%

Bond Expense – Bond discount/premium and issuance expenses are being amortized using the effective interest method over the terms of the related bond issues.

Allowance for Doubtful Accounts – The District has provided for an allowance for doubtful accounts of $64.4 million and $67.5 million as of April 30, 2003 and 2002, respectively.

Nuclear Fuel – The District amortizes the cost of nuclear fuel using the units of production method. The nuclear fuel amortization and the disposal expense are components of fuel expense. Accumulated amortization of nuclear fuel at April 30, 2003 and 2002 was $337.3 million and $318.4 million, respectively.

Nuclear Decommissioning – The total cost to decommission the District's 17.49% share of Palo Verde Nuclear Generating Station (PVNGS) is estimated to be $344.9 million, in 2001 dollars. This estimate is based on a site specific study prepared by an independent consultant, assuming the prompt removal/dismantlement method of decommissioning authorized by the Nuclear Regulatory Commission (NRC). This study is updated as required, every three years, and was last updated in the fall of 2001. Based on the 2001 site study, the District estimates its share of ultimate decommissioning expenditures will be $1.8 billion. Current decommissioning funding levels assume earnings on the decommissioning funds of 7.65%, as well as a future annual escalation rate of 5.92% in decommissioning costs. The actual decommissioning costs may vary from the estimate. Expenditures for decommissioning activities are anticipated over a 14-year period beginning in 2024. Estimated decommissioning costs are accrued over the estimated useful life of PVNGS. The liability associated with decommissioning is included in deferred credits and other non-current liabilities in the accompanying Combined Balance Sheets and amounted to $99.7 million and $93.5 million as of April 30, 2003 and 2002, respectively. Decommissioning expense, net of earnings on trust fund assets, of $2.9 million and $3.6 million was recorded in fiscal years 2003 and 2002, respectively. The District contributes to a trust set up in accordance with the NRC requirements. Decommissioning funds of $114.5 million and $121.4 million, stated at market value, as of April 30, 2003 and 2002, respectively, are held in the trust and are classified as segregated funds in the accompanying Combined Balance Sheets. Unrealized gains on decommissioning fund assets of $17.0 million and $28.2 million at April 30, 2003 and 2002, respectively, are included in deferred credits and other non-current liabilities in the accompanying Combined Balance Sheets. See *Recently Issued Accounting Standards*, at the end of this note, for information on a new accounting standard that impacts nuclear decommissioning accounting.

Accounting for Energy Risk Management Activities – The District has an energy risk management program to limit exposure to risks inherent in normal energy business operations. The goal of the energy risk management program is to measure and minimize exposure to market risks, credit risks and operational risks. Specific goals of the energy risk management program include reducing the impact of market fluctuations on energy commodity prices associated with customer energy requirements, excess generation and fuel expenses, in addition to meeting customer pricing needs, and maximizing the value of physical generating assets. The District employs established policies and procedures to meet the goals of the energy risk management program using various physical and financial instruments, including forward contracts, futures, swaps and options. Certain of these transactions are accounted for under Statement of Financial Accounting Standards No. 133, "*Accounting for Derivative Instruments and Hedging Activities,*" as amended (SFAS No. 133). Under SFAS No. 133, derivative instruments are recorded in the balance sheet as either an asset or liability measured at their fair value. The standard also requires changes in the fair value of the derivative be recognized each period in current earnings or other comprehensive income depending on the purpose for using the derivative and/or its qualification, designation and effectiveness as a hedging transaction. Most of the District's contractual agreements qualify for the normal purchases and sales exception allowed under SFAS No. 133 and are not recorded at market value. For further explanation of the effects of SFAS No. 133 on the District's financial results see *Note (3) "Accounting for Derivative Instruments and Hedging Activities."*

Concentrations of Market and Credit Risk – Market risk is the risk that changes in market prices or customer demand will adversely affect earnings and cash flows. Industry movements towards competition in electric generation subject the District to market risk associated with energy commodities such as electric power and natural gas. Recovery of costs to produce electricity in a non-regulated environment will be affected by changes in competitive market prices for both production resources and the market price of energy sales to ultimate customers.

The use of contractual arrangements to manage the risks associated with changes in energy commodity prices creates credit risk exposure resulting from the possibility of nonperformance by counter-parties pursuant to the terms of their contractual obligations. In addition, volatile energy prices can create significant credit exposure from energy market receivables. The District has a credit policy for wholesale counter-parties, and continuously monitors credit exposures, routinely assesses the financial strength of its counter-parties, minimizes credit risk by dealing primarily with creditworthy counter-parties, entering into standardized agreements which allow netting of exposures to and from a single counter-party and by requiring letters of credit, parent guarantees or other collateral when it does not consider the financial strength of a counter-party sufficient.

Income Taxes – The District is exempt from federal and Arizona state income taxes. Accordingly, no provision for income taxes has been recorded for the District in the accompanying combined financial statements.

New West Energy recognizes deferred tax liabilities and assets for the expected future tax consequences of events that have been recognized in its financial statements or tax returns. Deferred tax liabilities and assets are determined based on differences between the financial statement carrying amounts and tax bases of assets and liabilities using enacted tax rates in effect in the years in which the differences are expected to reverse. Since its inception in May 1997, the tax effect of New West Energy's results of operations has been immaterial.

Cash Equivalents – The District treats short-term temporary cash investments with original maturities of three months or less as cash equivalents.

Revenue Recognition – The District recognizes revenue when billed and accrues estimated revenue for electricity delivered to customers that has not yet been billed.

Materials and Supplies, and Fuel Stocks – Materials and supplies are stated at lower of market or average cost. Fuel stocks are stated at lower of market or weighted average cost.

Reclassifications – For comparative purposes, certain prior year amounts have been reclassified to conform with the current year presentation.

The District reclassified $17.0 million and $28.2 million in fiscal years 2003 and 2002, respectively, related to unrealized gains on decommission trust fund assets from other comprehensive income to deferred credits and other non-current liabilities to conform with industry practice.

Recently Issued Accounting Standards – The Financial Accounting Standards Board (FASB) has recently issued the following Statement of Financial Accounting Standards (SFAS) and FASB Interpretations (FIN) that may have financial impacts on the District:

SFAS No. 143, *"Accounting for Asset Retirement Obligations"* (SFAS No. 143), provides accounting requirements for the recognition and measurement of liabilities for legal obligations associated with the retirement of tangible long-lived assets. Under the standard, these liabilities will be recognized at fair value as incurred and capitalized as part of the cost of the related tangible long-lived assets. Accretion of the liabilities due to the passage of time will be an operating expense and the capitalized cost will be depreciated over the useful life of the long-lived asset. Retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which a legal obligation exists under enacted laws, statutes written or oral contracts, including obligations arising under the doctrine of promissory estoppel.

The District adopted SFAS No. 143 on May 1, 2003. Prior to adopting SFAS No. 143, costs for removal of most assets were expensed when incurred or accrued as an additional component of operating expense. Under SFAS No. 143, only the costs to remove an asset with legally binding retirement obligations will be accrued over time through accretion of the asset retirement obligation and depreciation of the capitalized asset retirement cost.

The District has identified retirement obligations for the Palo Verde Nuclear Generating Station, Navajo Generating Station, Four Corners Generating Station and certain other assets. On May 1, 2003, the District recorded a liability of $173.5 million for asset retirement obligations, including the accretion impacts; a $63.1 million increase in the carrying amount of the associated assets; a net decrease of $99.7 million in accumulated decommissioning liability related primarily to the reversal of the previously recorded accumulated decommissioning and other removal costs related to these obligations; a charge to earnings as a cumulative effect of $10.7 million.

Amounts recorded under SFAS No. 143 are subject to various assumptions and determinations, such as determining whether an obligation exists to remove assets, estimating the fair value of the costs of removal, estimating when final removal will occur, and the credit-adjusted risk-free interest rates to be utilized on discounting future liabilities. Changes that may arise over time with regard to these assumptions and determinations will change amounts recorded in the future as expense for asset retirement obligations.

SFAS No. 146, *"Accounting for Costs Associated with Exit or Disposal Activities"* (SFAS No. 146), requires the recognition of a liability for costs related to exit or disposal activities when the costs are incurred. Previous accounting guidance required the liability to be recorded at the date of commitment to an exit or disposal plan. The provisions of this statement are effective for exit or disposal activities that are initiated after December 31, 2002. Future exit or disposal plans will be accounted for under SFAS No. 146.

SFAS No. 149, *"Amendment of Statement 133 on Derivative Instruments and Hedging Activities"* (SFAS No. 149), amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts (collectively referred to as derivatives) and for hedging activities under SFAS No. 133. The provisions of SFAS No. 149 relating to SFAS No. 133 Implementation Issues should continue to be applied in accordance with their respective effective dates. In general, other provisions are applied prospectively to contracts entered into or modified after June 30, 2003. The District is evaluating the impact of SFAS No. 149 on the combined financial statements.

FIN No. 45, *"Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others"* (FIN No. 45), provides requirements related to the guarantor's accounting for, and disclosure of, the issuance of certain types of guarantees and indemnifications. The initial recognition and measurement provisions of FIN No. 45 apply on a prospective basis to guarantees and indemnifications issued or modified after December 31, 2002. The disclosure requirements are effective for annual periods ending after December 15, 2002. For further explanation of the District's guarantees and indemnifications, see *Note (11) "Commitments"* and *Note (12) "Contingencies."* FIN No. 45 is not expected to have a material impact on the District's financial statements; however, it could impact the District's financial statements in the future.

FIN No. 46, *"Consolidation of Variable Interest Entities, an Interpretation of Accounting Research Bulletin No. 51"* (FIN No. 46), provides guidance on the identification and consolidation of entities for which control is achieved through means other than voting rights (variable interest entities). FIN No. 46 also requires additional disclosures describing transactions with variable interest entities in which consolidation is not required. FIN No. 46 is effective immediately for any variable interest entity created after January 31, 2003 and is effective July 1, 2003 for any variable interest entity created before February 1, 2003. The District is evaluating the impact of FIN No. 46 on the combined financial statements.

3. Accounting for Derivative Instruments and Hedging Activities:

Effective May 1, 2001, the District adopted SFAS No. 133, as amended. SFAS No. 133 requires that entities recognize all derivatives as either assets or liabilities in the balance sheet and measure those instruments at fair value. Changes in the fair value of derivative financial instruments are either recognized periodically in net revenues or accumulated net revenues (as a component of other comprehensive income), depending on whether or not the derivative meets specific hedge accounting criteria. The criteria includes a requirement for hedge effectiveness, which is measured based on the relative changes in fair value between the derivative contract and the hedged item over time. Changes in the fair value resulting from ineffectiveness are recognized immediately in net revenues.

The District enters into contracts for electricity, natural gas and other energy commodities to meet the expected needs of its retail customers. The District sells excess capacity during periods when it is not needed to meet retail requirements. The District's energy risk management program uses various physical and financial contracts to hedge exposures to fluctuating commodity prices. The District examines contracts at inception to determine the appropriate accounting treatment. If a contract does not meet the derivative criteria, or if it qualifies for the SFAS No. 133 normal purchases and sales scope exception, the District accounts for the contract using settlement accounting (costs and revenues are recorded when physical delivery occurs). For contracts that qualify as a derivative and do not meet the SFAS No. 133 normal purchases and sales scope exception, the District further examines the contract to determine if it qualifies for hedge accounting. If a contract does not meet the hedging criteria in SFAS No. 133, the District recognizes the changes in the fair value of the derivative instrument in net revenues each period (mark-to-market). If the contract does qualify for hedge accounting, changes in the fair value are recorded in accumulated net revenues and other comprehensive income (as a component of other comprehensive income).

The District formally documents all relationships between hedging instruments and hedged items, as well as its risk-management objective and strategy for undertaking various hedge transactions. This process includes linking all derivatives to the forecasted transactions. The District also formally assesses (both at the hedge's inception and on an ongoing basis) whether the derivatives that are used in hedging transactions have been highly effective in offsetting changes in cash flows of hedged items and whether those derivatives may be expected to remain highly effective in future periods. When it is determined that a derivative is not (or has ceased to be) highly effective as a hedge, the District discontinues hedge accounting prospectively, as discussed below.

The District discontinues hedge accounting prospectively when: (1) it determines that the derivative is no longer effective in offsetting changes in cash flows of a hedged item; (2) the derivative expires or is sold, terminated, or exercised; (3) it is no longer probable that the forecasted transaction will occur; or (4) management determines that designating the derivative as a hedging instrument is no longer appropriate.

When the District discontinues hedge accounting because it is no longer probable that the forecasted transaction will occur in the originally expected period, the gain or loss on the derivative is reclassified into net revenues. If the derivative remains outstanding, the District will carry the derivative at its fair value on the balance sheet, recognizing changes in the fair value in current-period net revenues.

As a result of adopting SFAS No. 133 and guidance issued by the FASB's Derivative Implementation Group (DIG) effective during fiscal year 2002, the District recognized $98.1 million of derivative assets and $80.5 million of derivative liabilities in the Combined Balance Sheets as of May 1, 2001. Also as of May 1, 2001, the District recorded an $11.8 million gain in net revenues and a $5.8 million gain in accumulated net revenues and other comprehensive income (as a component of other comprehensive income), both as a cumulative effect of a change in accounting principle.

In December 2001, the DIG issued revised guidance on the accounting for electricity contracts with option characteristics and the accounting for contracts that combine a forward contract and a purchased option contract. The effective date for the revised guidance for the District was May 1, 2002. As a result of this new guidance the District recognized $16.6 million of derivative assets and $23.3 million of derivative liabilities in the Combined Balance Sheets as of May 1, 2002. Also as of May 1, 2002, the District recorded a $6.7 million loss in combined net revenues as a cumulative effect of change in accounting principle.

As of April 30, 2003 and 2002, the valuation of market changes for the District's energy risk management contracts resulted in an increase (decrease) in electric revenues of $12.7 million and $(11.6) million, respectively, and an increase (decrease) in fuel expenses of $(7.8) million and $44.4 million, respectively. The impact to combined net revenues for fiscal year 2003 and 2002 was an unrealized gain (loss) of $20.5 million and $(44.2) million, respectively. Accumulated net revenues and other comprehensive income (as a component of other comprehensive income), were increased by $0.1 million and $2.3 million due to unrealized cash flow hedge gains as of April 30, 2003 and 2002, respectively. The following table summarizes the District's derivative related assets and liabilities at April 30 (in thousands):

	2003	*2002*
Other Current Assets	$ 29,794	$ 3,383
Deferred Charges and Other Assets	27,586	12,514
Other Current Liabilities	(31,274)	(18,552)
Deferred Credits and Other Non-Current Liabilities	(47,279)	(39,289)
Net Asset (Liability)	$ (21,173)	$ (41,944)

4. Accumulated Net Revenues and Other Comprehensive Income:

The following table summarizes accumulated net revenues and other comprehensive income (in thousands):

	Accumulated Net Revenues	*Accumulated Other Comprehensive Income (Loss)*	*Accumulated Net Revenues and Other Comprehensive Income*
Balance, April 30, 2001	$ 2,245,791	$ 35,988	$ 2,281,779
Net revenues	19,796	-	19,796
Cumulative effect of change in accounting principle	-	5,765	5,765
Unrealized gain on derivative instruments	-	2,255	2,255
Reclassification of realized gain to income	-	(5,765)	(5,765)
Net unrealized loss on available-for-sale securities	-	(1,740)	(1,740)
Balance, April 30, 2002	$ 2,265,587	$ 36,503	$ 2,302,090
Net revenues	46,669	-	46,669
Minimum pension liability	-	(127,900)	(127,900)
Unrealized gain on derivative instruments	-	87	87
Reclassification of realized loss to income	-	134	134
Net unrealized loss on available-for-sale securities	-	(17,152)	(17,152)
Balance, April 30, 2003	$ 2,312,256	$ (108,328)	$ 2,203,928

The majority of net unrealized loss on available-for-sale securities originates from segregated fund investments. Net unrealized gain (loss) on available-for-sale securities consists of gross unrealized (loss) on equity funds of $(20.0) million and $(1.2) million and gross unrealized gain (loss) on debt funds of $2.8 million and $(0.5) million at April 30, 2003 and 2002, respectively.

5. Long-Term Debt:

Long-term debt consists of the following at April 30 (in thousands):

	Interest Rate	*2003*	*2002*
Revenue bonds (mature through 2032)	3.0% – 6.5%	$ 2,648,084	$ 2,613,259
Unamortized bond discount/premium		46,925	10,012
Total revenue bonds outstanding		2,695,009	2,623,271
Commercial paper	1.0% – 1.3%	375,000	525,000
Total long-term debt		3,070,009	3,148,271
Less — current portion		(260,428)	(114,340)
Total long-term debt, net of current portion		$ 2,809,581	$ 3,033,931

The annual maturities of long-term debt (excluding commercial paper and unamortized bond discount/premium) as of April 30, 2003, due in the fiscal years ending April 30, are as follows (in thousands):

2004	$ 260,428
2005	171,456
2006	274,793
2007	115,061
2008	134,766
Thereafter	1,691,580
	$ 2,648,084

Revenue Bonds – Revenue bonds are secured by a pledge of, and a lien on, the revenues of the electric system, after deducting operating expenses, as defined in the bond resolution. Under the terms of the new bond resolution, effective in January 2003, the District is no longer required to make monthly deposits to an externally trusted debt service fund for the payment of future principal and interest. However, the District is continuing to make debt service deposits to a non-trusted segregated fund. Included in segregated funds in the accompanying Combined Balance Sheets is $210.7 million and $149.1 million of debt service related funds as of April 30, 2003 and 2002, respectively.

The District has $65.3 million of mini-revenue bonds outstanding which are redeemable at the option of the bondholder under certain circumstances. Based on historical redemptions made on these bonds, management believes there are sufficient funds available to cover potential redemptions in any year.

The debt service coverage ratio, as defined in the bond resolution, is used by bond rating agencies to help evaluate the financial viability of the District. For the years ended April 30, 2003 and 2002, the debt service coverage ratio was 2.23 and 3.09, respectively.

Interest and the amortization of the bond discount and issue expense on the various issues results in an effective rate of 5.09% over the remaining term of the bonds.

The District has authorization to issue additional Electric System Revenue Bonds totaling $602.7 million principal amount and Electric System Refunding Revenue Bonds totaling $2.4 billion principal amount, net of amounts issued in fiscal year 2003. These amounts do not include $580.0 million in Electric System Revenue Bonds and $640.0 million in Electric System Refunding Revenue Bonds requested in an application currently pending before the Arizona Corporation Commission.

In December 2001, the District issued $580.6 million of Electric System Refunding Revenue Bonds. The net proceeds from these bonds were used to defease outstanding revenue bonds with par amounts of $605.1 million. The defeasance

is expected to reduce total debt payments over the life of the bonds by $426.2 million and is expected to result in present value savings of approximately $30.2 million. This transaction resulted in a net loss for accounting purposes of $34.6 million, which was deferred and will be amortized over the life of the bonds to be refunded as authorized by the Board.

In February 2002, the District issued $432.6 million of Electric System Refunding Revenue Bonds. The net proceeds from these bonds were used to defease outstanding bonds with par amounts of $437.4 million. The defeasance is expected to reduce total debt payments over the life of the bonds by $21.4 million and is expected to result in present value savings of approximately $29.6 million. This transaction resulted in a net loss for accounting purposes of $26.1 million, which was deferred and will be amortized over the life of the bonds to be refunded as authorized by the Board.

In August 2002, the District defeased, with cash, $408.0 million of its outstanding revenue bonds. The defeasance is expected to reduce total debt payments over the life of the bonds by $681.2 million. This transaction resulted in a net loss for accounting purposes of $25.0 million, which was deferred and will be amortized over the life of the defeased bonds.

In September 2002, the District issued $570.0 million of Electric System Revenue Bonds. The net proceeds from these bonds are being used to fund distribution capital requirements.

In November 2002, the District issued $202.4 million of Electric System Refunding Revenue Bonds. The net proceeds from these bonds were used to defease outstanding revenue bonds with par amounts of $209.8 million. The defeasance is expected to reduce total debt payments over the life of the bonds by $296.2 million and is expected to result in present value savings of approximately $7.4 million. This transaction resulted in a net loss for accounting purposes of $13.9 million, which was deferred and will be amortized over the life of the bonds to be refunded.

In November 2002, the District issued $104.1 million of Electric System Refunding Revenue Bonds. The net proceeds from these bonds were used to defease outstanding revenue bonds with par amounts of $113.3 million. The defeasance is expected to reduce total debt payments over the life of the bonds by $226.0 million and is expected to result in present value savings of approximately $13.2 million. This transaction resulted in a net loss for accounting purposes of $6.4 million, which was deferred and will be amortized over the life of the bonds to be refunded.

Commercial Paper – The District has $375.0 million of outstanding tax-exempt Series B Commercial Paper. The District has retired the $150.0 million of tax-exempt Series A Commercial Paper as of April 30, 2003. The Series B issue has an average weighted interest rate to the District of 1.1%.

The commercial paper matures not more than 270 days from the date of issuance and is an unsecured obligation of the District. The District has the ability to refinance the outstanding commercial paper on a long-term basis in connection with its revolving line of credit that supports the commercial paper and is available through April 10, 2006. As such, the District has classified the commercial paper as long-term debt in the Combined Balance Sheets as of April 30, 2003.

While the revolving credit agreement contains covenants that could prohibit borrowing under certain conditions, management believes financing would be available. The District has never borrowed under the agreement and management does not expect to do so in the future. Alternative sources of funds to support the commercial paper program include existing funds on hand or the issuance of alternative debt, such as revenue bonds.

Line-of-Credit Arrangements – The District has a $375.0 million revolving line-of-credit agreement that supports the $375.0 million tax-exempt Series B Commercial Paper Program. The District also had a $150.0 million revolving

line-of-credit agreement that expired on May 6, 2003 which supported the $150.0 million tax-exempt Series A Commercial Paper Program that was retired on April 30, 2003. These agreements have various covenants, with which the District was in compliance at April 30, 2003.

6. Fair Value of Financial Instruments:

The following methods and assumptions were used to estimate the fair value of each class of financial instruments identified in the following items in the accompanying Combined Balance Sheets.

Investments in Marketable Securities – The District invests in U.S. government obligations, certificates of deposit and other marketable investments. Such investments are classified as other investments, segregated funds, cash and cash equivalents or temporary investments in the accompanying Combined Balance Sheets depending on the purpose and duration of the investment. The fair value of marketable securities with original maturities greater than one year is based on published market data. The carrying amount of marketable securities with original maturities of one year or less approximates their fair value because of their short-term maturities.

Long-Term Debt – The fair value of the District's revenue bonds, including the current portion, was estimated by using pricing scales from independent sources. The carrying amount of commercial paper approximates the fair value because of its short-term maturity.

Other Current Assets and Liabilities – The carrying amounts of receivables, accounts payable, customers' deposits and other current liabilities in the accompanying Combined Balance Sheets approximate fair value because of their short-term maturities.

The estimated carrying amounts and fair values of the District's financial instruments, at April 30, are as follows (in thousands):

	2003		*2002*	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Investments in marketable securities:				
Other investments	$ 15,000	$ 15,032	$ 34,000	$ 34,579
Segregated funds	653,968	657,488	449,340	451,144
Temporary investments	57,925	58,013	185,463	186,294
Long-term debt	3,070,009	3,230,661	3,148,271	3,245,100

Accounting for Debt and Equity Securities – The District's investments in debt securities are reported at amortized cost if the intent is to hold the security to maturity. At April 30, 2003, the District's investments in debt securities have maturity dates ranging from May 6, 2003 to February 28, 2012. Other debt and equity securities are reported at market, with unrealized gains or losses included as a separate component of Accumulated Net Revenues and Other Comprehensive Income. The District's investments in debt and equity securities are included in temporary investments, segregated funds and non-utility property and other investments in the accompanying Combined Balance Sheets.

7. Employee Benefit Plans and Incentive Programs:

Defined Benefit Pension Plan and Other Post-Retirement Benefits – SRP's Employees' Retirement Plan (the Plan) covers substantially all employees. The Plan is funded entirely from SRP contributions and the income earned on invested Plan assets. No contributions were required in fiscal years 2003 or 2002.

The Plan assets consist primarily of stocks, U.S. government obligations, corporate bonds and real estate funds.

SRP provides a non-contributory defined benefit medical plan for retired employees and their eligible dependents (contributory for employees hired January 1, 2000 or later) and a non-contributory defined benefit life insurance plan for retired employees. Employees are eligible for coverage if they retire at age 65 or older with at least five years of vested service under the Plan (ten years for those hired January 1, 2000 or later), or any time after attainment of age 55 with a minimum of ten years of vested service under the Plan (20 years for those hired January 1, 2000 or later). The funding policy is discretionary and is based on actuarial determinations. The unrecognized transition obligation is being amortized over 20 years, beginning in 1994.

The following tables outline changes in benefit obligations, plan assets, the funded status of the plans and amounts included in the combined financial statements as of April 30, based on January 31 valuation dates (in thousands):

	Pension Benefits		*Other Benefits*	
	2003	*2002*	*2003*	*2002*
Change in benefits obligation:				
Benefit obligation at beginning of year	$ 644,700	$ 567,300	$ 279,900	$ 215,400
Service cost	18,200	17,000	7,200	5,600
Interest cost	45,700	41,600	19,900	15,800
Amendments	17,800	-	(14,900)	-
Actuarial loss	83,600	48,500	30,600	52,100
Benefits paid	(31,000)	(29,800)	(10,700)	(9,000)
Benefit obligations at end of year	$ 779,000	$ 644,600	$ 312,000	$ 279,900
Change in plan assets:				
Fair value of plan assets at beginning of year	$ 639,600	$ 705,100	$ -	$ -
Actual return on plan assets	(63,000)	(35,700)	-	-
Employer contributions	-	-	10,700	9,000
Benefits paid	(31,000)	(29,800)	(10,700)	(9,000)
Fair value of plan assets at end of year	$ 545,600	$ 639,600	$ -	$ -
Funded status	$ (233,400)	$ (5,000)	$ (312,000)	$ (279,900)
Unrecognized transition obligation	-	-	41,100	62,300
Unrecognized net actuarial loss	245,600	37,000	110,400	83,500
Unrecognized prior service cost	25,400	8,700	600	-
Post January 31 contributions	-	-	2,700	3,000
Net asset (liability) recognized	$ 37,600	$ 40,700	$ (157,200)	$ (131,100)
Amounts recognized in Combined Balance Sheets:				
Prepaid benefit cost	$ 37,600	$ 40,700	$ -	$ -
Accrued benefit liability	-	-	(157,200)	(131,100)
Additional minimum liability	(153,300)	-	-	-
Intangible asset	25,400	-	-	-
Accumulated other comprehensive income	127,900	-	-	-
Net amount recognized	$ 37,600	$ 40,700	$ (157,200)	$ (131,100)

The District internally funds its other post-retirement benefits obligation. At April 30, 2003 and 2002, $152.3 million and $163.9 million of segregated funds, respectively, were designated for this purpose.

Weighted average assumptions used to calculate actuarial present values of benefit obligations were as follows:

	Pension Benefits		*Other Benefits*	
	2003	*2002*	*2003*	*2002*
Discount rate	6.75%	7.25%	6.75%	7.25%
Expected return on plan assets	8.25%	8.75%	N/A	N/A
Rate of compensation increase	4.0%	4.0%	4.0%	4.0%

For employees who retire at age 65 or younger, for measurement purposes, a 9.0% annual increase before attainment of age 65 and a 11.0% annual increase on and after attainment of age 65 in per capita costs of health care benefits were assumed during 2003; these rates were assumed to decrease uniformly until equaling 5.0% in all future years.

Components of net periodic benefit (gain) costs for the years ended April 30, are as follows (in thousands):

	Pension Benefits		*Other Benefits*	
	2003	*2002*	*2003*	*2002*
Service cost	$ 18,200	$ 17,000	$ 7,200	$ 5,600
Interest cost	45,800	41,600	19,900	15,800
Expected return on plan assets	(62,000)	(61,300)	-	-
Amortization of transition obligation (asset)	-	(4,000)	5,600	5,700
Recognized net actuarial loss (gain)	-	(2,400)	4,200	800
Amortization of prior service cost	1,100	1,100	-	-
Net periodic benefit (gain) cost	$ 3,100	$ (8,000)	$ 36,900	$ 27,900

Assumed health care cost trend rates have a significant effect on the amounts reported for health care plans. A one-percentage-point change in the assumed health care cost trend rates would have the following effect (in thousands):

	One-Percentage-Point Increase	One-Percentage-Point Decrease
Effect on total service cost and interest cost components	$ 4,600	$ (4,100)
Effect on post-retirement benefit obligation	$ 45,000	$ (40,000)

Defined Contribution Plan – SRP's Employees' 401(k) Plan (the 401(k) Plan) covers substantially all employees. The 401(k) Plan receives employee pre-tax and post-tax contributions and partial employer matching contributions. Employer matching contributions to the 401(k) Plan were $8.4 million and $7.1 million during fiscal years 2003 and 2002, respectively.

Employee Incentive Compensation Program – SRP has an incentive compensation program covering substantially all regular employees. The incentive compensation amount is based on achievement of pre-established targets. An accrual of $8.3 million for fiscal year ended April 30, 2003 is included in other current liabilities in the accompanying Combined Balance Sheets. This liability is stated net of receivables from participants in jointly-owned electric plants of $0.9 million at April 30, 2003. The incentive targets were not met in fiscal year 2002.

8. Interests in Jointly-Owned Electric Utility Plants:

The District has entered into various agreements with other electric utilities for the joint ownership of electric generating and transmission facilities. Each participating owner in these facilities must provide for the cost of its ownership share. The District's share of expenses of the jointly-owned plants is included in operating expenses in the accompanying Combined Statements of Net Revenues.

The following table reflects the District's ownership interest in jointly-owned electric utility plants as of April 30, 2003 (in thousands):

Generating Station	Ownership Share	Plant in Service	Accumulated Depreciation	Construction Work in Progress
Four Corners (NM) (Units 4 & 5)	10.00%	$ 102,564	$ 90,236	$ 3,441
Mohave (NV) (Units 1 & 2)	20.00%	131,900	96,482	10,063
Navajo (AZ) (Units 1, 2 & 3)	21.70%	345,003	219,442	3,827
Hayden (CO) (Unit 2)	50.00%	113,178	66,355	976
Craig (CO) (Units 1 & 2)	29.00%	243,104	154,672	1,748
PVNGS (AZ) (Units 1, 2 & 3)	17.49%	1,103,042	794,178	54,167
		$2,038,791	$1,421,365	$ 74,222

The District acts as the operating agent for the participants in the Navajo Generating Station (NGS). On November 30, 2001, the District acquired half (10%) of the interest in the Mohave Generating Station held by the Los Angeles Department of Water and Power, thereby increasing the District's total share to 20%.

9. Capital Lease:

In fiscal year 2001, the District entered into a ten-year contract with Reliant Energy Desert Basin, LLC (Reliant) for the long-term exclusive purchase of power and energy produced at Reliant's facility located in Central Arizona. The amount of capacity available to the District is approximately 598 MW annually. The payments include costs for both capacity and operation and maintenance of the facility. Upon inception of the contract, the present value of the fixed payment attributable to capacity costs meets the requirement for accounting for this contract as a capital lease. Accordingly, in fiscal year 2002, the District recorded the present value of the capacity payments of $292.1 million as utility plant and the related capital lease obligation in deferred credits and other non-current liabilities (long-term portion) and other current liabilities (short-term portion). At April 30, 2003 and 2002, the utility plant under the capital lease was $246.8 million and $277.0 million, net of accumulated amortization of $45.3 million and $15.1 million, respectively. The capital lease obligation was $251.4 million and $276.7 million at April 30, 2003 and 2002, respectively. The capacity payments required under the agreement total $40.9 million annually through fiscal year 2008, and $108.3 million thereafter. The operation and maintenance payments required under the agreement total $21.5 million annually through fiscal year 2008, and $57.0 million thereafter.

10. Regulatory Issues:

Fundamental Changes in the Electric Utility Industry – The District historically operated in a highly-regulated environment in which it had an obligation to deliver electric service to customers within its service area. In May 1998, the Arizona Electric Power Competition Act (the Act) authorized competition in the retail sale of electric generation, recovery of stranded costs and competition in billing, metering and meter reading.

The Act allows a temporary surcharge on electric distribution service prices to pay for all or a portion of unmitigated stranded costs of electric generation service incurred as a direct result of the onset of competition. Such costs must have been incurred to serve customers in Arizona before December 26, 1996. This surcharge may not continue past December 31, 2004, and must not cause prices to exceed the prices in effect on December 30, 1998.

In May 2002, the legislature established a committee to examine the status of deregulation and determine whether the Act should be modified. The committee met during 2002 and issued a final report on June 12, 2003, with its recommendation to continue to study the Act. The committee is expected to be reappointed in 2003 to continue its evaluation of retail competition and possible changes to the Act.

In 1999, the Arizona Corporation Commission (the Commission), which regulates public service corporations, approved final rules for retail electric competition. The Commission subsequently entered into agreements with each of its regulated utilities, establishing terms and conditions precedent to a framework for stranded cost recovery and unbundled tariffs. Beginning January 1, 2001, all customers were given the right to select an alternative generation provider. In 2002, due to California's unsuccessful experience with competition and other market developments, the Commission began a review of its existing competition rules to provide additional safeguards for consumers and to identify key issues that impede competition and areas that could be improved.

The Federal Energy Regulatory Commission (FERC) regulates the electric utility industry under the authority of various statutes. FERC issued rules in 1996 mandating, among other things, open nondiscriminatory access to transmission lines. The rules require comparable transmission service in order to use the transmission systems of public utilities. The District has filed a comparable open access transmission tariff to ensure reciprocal access, pursuant to rules FERC developed for non-jurisdictional entities like the District. In addition, FERC issued its Order No. 2000 in December 1999, requiring all jurisdictional public utilities that own, operate or control interstate transmission to attempt to develop proposals for regional transmission organizations (RTO). The District is participating in the development of an RTO for the Southwest.

The Changing Regulatory Environment – By 2001, the District had opened its service area to competition in generation and billing, metering and meter reading. The District's electric distribution area remains regulated by its Board and the District will not provide distribution services in the distribution areas of other utilities.

The District's price plans have been unbundled since 1999. The District reviewed its price plans in November 2001 and approved, among other things, a Fuel and Purchase Power Adjustment Mechanism (Adjustment Mechanism) that became effective May 1, 2002. The Adjustment Mechanism provides for a prospective collection of amounts for fuel and purchased power costs above predetermined levels. Other changes to the District's price plans became effective December 31, 2001. The District prices its electric generation based upon market and cost of service factors.

Since December 31, 1998, the District has been recovering stranded costs through a competitive transition charge (CTC) paid by all distribution customers. Effective June 2004, the District will stop collecting the CTC. In fiscal year 2001 management determined, based upon projections using current economic conditions, that the full CTC of $795.0 million might not be collected. Management, therefore, reduced the amount of the CTC asset and took a charge to depreciation and amortization expense of $85.0 million as of April 30, 2001. Further, as part of the November 2001 price plans review, the District reviewed the level of its CTC associated with stranded cost recovery and elected to retain the CTC at its current level until June 1, 2004.

Through a surcharge to the District's transmission and distribution customers, the District recovers the costs of programs benefiting the general public, such as discounted rates for the elderly or impoverished, efficiency programs, demand-side management measures, renewable energy programs, economic development, research and development and nuclear decommissioning, including the cost of spent fuel storage. These surcharges have been separately identified and included in the District's price plans for the regulated portion of its operations.

Regulatory Accounting – The District accounts for the financial effects of the regulated portion of its operations in accordance with the provisions of SFAS No. 71, which requires cost-based, rate-regulated utilities to reflect the impacts of regulatory decisions in their financial statements.

As a result of the Board actions in August 1998 to open the District's service area to competition in generation, the District discontinued the application of SFAS No. 71 to its electric generation operations in fiscal year 1999. From that time forward, the provisions of SFAS No. 101, *"Regulated Enterprises: Accounting for the Discontinuation of Application of FASB Statement No. 71,"* have been applied to the portion of its business no longer meeting the provisions of SFAS No. 71.

In fiscal year 1999, the District evaluated the carrying amounts of its generation operations in relation to future cash flows expected to be generated from their use in a competitive environment and determined that $850.2 million of these assets were impaired. Impairment of $631.8 million was attributable to generation operations, and $163.7 million was attributable to long-term energy contracts. Of the total impairment, a maximum of $795.0 million may be recovered through the CTC, and such amount was recorded as a regulatory asset (CTC regulatory asset). The CTC regulatory asset will be recovered through the competitive transition charge over the period beginning December 31, 1998, and continuing through May 31, 2004. Since December 31, 1998, the District has amortized or charged $657.7 million of CTC asset to depreciation and amortization expense and recovered $606.3 million through CTC revenue.

Regulatory assets for spent nuclear fuel storage are being amortized over the life of the nuclear plant. Bond defeasance regulatory assets are being amortized over different periods, beginning in fiscal year 1997 and ending in fiscal year 2031. Regulatory assets are included in deferred charges and other assets on the accompanying Combined Balance Sheets.

Mohave Generating Station – The District and the other Participants in the Mohave Generating Station (Mohave) entered into a settlement with the Sierra Club that requires the installation of pollution abatement equipment by the end of 2005 if the plant will continue to be operated with coal. (See Note (12) "Contingencies," for additional information on air quality issues.) In addition, the initial term of the coal supply agreement serving Mohave expires at the end of 2005 and the Hopi Tribe has demanded that pumping water for the slurry pipeline serving Mohave cease by the end of 2005. The Mohave Participants, in turn, have refused to commit to install pollution abatement equipment without reasonable assurance that water will be available to deliver coal to the plant. Due to the lead-time required to order and install the pollution abatement equipment, the plant will likely cease operations at the end of 2005 for some period of time. The District and the other Mohave Participants are negotiating with various parties, including the Hopi Tribe, to extend the life of Mohave beyond 2005. The District's management is committed to this effort. If necessary, the District believes it will be able to replace the energy from other sources.

However, if the negotiations are not successful and the Mohave Participants are unable to secure the needed extension of the life of Mohave, the District will require an alternative means for recovering its investment in the plant. In that event, management received authorization from the Board to recover the balance of the District's investment in Mohave in its retail revenue requirements over the remainder of the scheduled useful life of the plant. Consequently, an analysis of the plant's future operating cash flows was performed resulting in a determination that it was not probable that the plant's carrying value would be realized through future revenues and a write-down of its carrying value of $66.2 million was recorded. In accordance with accounting standards for rate-regulated enterprises (SFAS No. 71), a regulatory asset was established for $66.2 million, based on the District's expectation that any unrecovered book value at the end of 2005 would be recovered in future rates.

Deferred charges and other assets consist primarily of the following at April 30 (in thousands):

	2003	2002
CTC regulatory asset	$ 137,764	$ 264,931
Bond defeasance regulatory asset	114,291	84,475
Mohave Generating Station regulatory asset	66,231	-
Spent nuclear fuel storage regulatory asset	22,418	22,209
Prepaid pension benefits	37,600	40,700
Derivatives market valuation	27,586	12,514
Pension intangible asset	25,400	-
Other	35,583	33,462
	$ 466,873	$ 458,291

If events were to occur making full recovery of these regulatory assets no longer probable, the District would be required to write off the remaining balance of such assets as a one-time charge to net revenues.

Deferred credits and other non-current liabilities consist primarily of the following at April 30 (in thousands):

	2003	2002
Capital lease obligation	$ 224,500	$ 251,364
Accrued post-retirement benefit liability	157,200	131,100
Additional pension minimum liability	153,300	-
Accrued decommissioning costs	116,725	121,710
Provision for contract losses	106,180	119,460
Derivatives market valuation	47,279	39,289
Accrued spent nuclear fuel storage	25,966	25,657
Other	83,207	84,106
	$ 914,357	$ 772,686

Operating results from the separable portion of the District's operations not meeting the provisions of SFAS No. 71 are as follows (in thousands):

	Fiscal Year Ended April 30, 2003	Fiscal Year Ended April 30, 2002
Operating revenues	$ 1,236,273	$ 1,459,451
Operating expenses	1,210,182	1,387,367
Net operating revenues from non-regulated operations	$ 26,091	$ 72,084

Utility plant assets used in the separable portion of the District's operations no longer meeting the provisions of SFAS No. 71 are as follows at April 30 (in thousands):

	2003	*2002*
Electric plant in service	$ 3,860,115	$ 3,887,948
Less accumulated depreciation	(2,275,461)	(2,119,902)
Net utility plant assets used in non-regulated operations	$ 1,584,654	$ 1,768,046

11. Commitments:

Subsidiary Guarantees – The District acts as guarantor for New West Energy's contractual obligations as necessary to satisfy performance security requirements under agreements with utility distribution companies, brokers and counterparties for financial hedge transactions and power purchasers and sellers. No payments were made under these guarantees during fiscal years 2003 and 2002. Existing guarantees were terminated May 31, 2003.

Improvement Program – The Improvement Program represents SRP's six-year plan for major construction projects and capital expenditures for existing generation, transmission, distribution and irrigation assets. For the 2004-2009 period, SRP estimates capital expenditures of approximately $2.4 billion. Major construction projects include expansion of generation at the Santan Generating Station, as well as other key strategic distribution and transmission projects.

Long-Term Power Contracts – The District entered into three contracts, collectively, with the United States Bureau of Reclamation (United States), the Western Area Power Administration and the Central Arizona Water Conservation District (CAWCD) for the long-term sale, through September 2011, of power and energy associated with the United States' entitlement to NGS. The amount of energy available to the District varies annually and is expected to decline over the life of the contracts. The District pays a fixed amount under the contracts, pays the cost of NGS generation and other related costs, and supplies energy at cost to CAWCD for Central Arizona Project facilities. The fixed portion of the District's payment obligations under the three contracts totals $47.0 million annually through fiscal year 2008, and $160.4 million thereafter. Of the total obligation, $25.2 million annually through fiscal year 2008 and $86.1 million thereafter are unconditionally payable regardless of the availability of power. Payments under these contracts totaled $99.4 million and $74.6 million in fiscal years 2003 and 2002, respectively.

The District entered into two other long-term power purchase agreements to obtain a portion of its projected load requirements through 2011. Minimum payments under these contracts are $40.6 million annually through fiscal year 2008 and $111.6 million thereafter. Total payments under these two contracts, including the minimum payments, were $61.9 million and $61.7 million in fiscal years 2003 and 2002, respectively. In conjunction with the impairment analysis performed on generation-related operations, the District has recorded provisions for losses on these contracts. The provisions recorded in August 1998, of $163.7 million, are being amortized over the life of the contracts, commencing January 1, 1999. Amortization of $13.3 million has been reflected as a reduction in purchased power expense in fiscal years 2003 and 2002. The remaining liability at April 30, 2003 of $106.2 million is included in deferred credits and other non-current liabilities in the Combined Balance Sheets.

Fuel Supply – At April 30, 2003, minimum payments under long-term coal supply contract commitments are estimated to be $156.8 million in fiscal year 2004, $148.0 million in fiscal year 2005, $120.9 million in fiscal year 2006, $91.7 million in fiscal year 2007, $62.7 million in fiscal year 2008, and $283.4 million thereafter.

12. Contingencies:

Nuclear Insurance – Under existing law, public liability claims arising from a single nuclear incident are limited to $9.5 billion. PVNGS participants insure for this potential liability through commercial insurance carriers to the maximum amount available ($200.0 million) with the balance covered by an industry-wide retrospective assessment program as required by the Price-Anderson Act. If losses at any nuclear power plant exceed available commercial insurance, the District could be assessed retrospective premium adjustments. The maximum assessment per reactor per nuclear incident under the retrospective program is $88.1 million including a 5% surcharge, applicable in certain circumstances, but not more than $10.0 million per reactor may be charged in any one year for each incident.

Based on the District's ownership share in PVNGS, the maximum potential assessment would be $46.2 million, including the 5% surcharge, but would be limited to $5.2 million per incident in any one year.

Spent Nuclear Fuel – Under the Nuclear Waste Policy Act of 1982, the District pays 1/10 of one cent per kWh on its share of net energy generation at PVNGS to the Department of Energy (DOE). The DOE was responsible for the selection and development of repositories for permanent storage and disposal of spent nuclear fuel not later than December 31, 1998. Because of the significant delays in the DOE's schedule, it cannot be determined when the DOE will accept waste from PVNGS or from the other owners of spent nuclear fuel. It is unlikely, due to PVNGS' position in DOE's queue for receiving spent fuel, that Arizona Public Service Company (APS), the operating agent of PVNGS, will be able to initiate shipments to DOE during the licensed life of PVNGS. Accordingly, APS is constructing an on-site dry cask storage facility to receive and store PVNGS spent fuel that is sufficient to provide storage for all three units for a 40-year operating life. The facility is expected to receive and store spent fuel at the end of 2002.

The District's share of on-site interim storage at PVNGS is estimated to be $28.3 million for costs to store spent nuclear fuel from inception of the plant through fiscal year-end 2003, and $1.8 million per year going forward. These costs have been included in the District's regulated operations price plans for transmission and distribution.

Navajo Nation Lawsuit – In June 1999, the Navajo Nation filed a lawsuit in the United States District Court in Washington, D.C., alleging that the coal supplier for the Navajo and Mohave Generating Stations (Peabody Coal Company), Southern California Edison Company, the District, and other defendants, had induced the United States to breach its fiduciary duty to the Navajo Nation and had violated federal racketeering statutes. The lawsuit arises out of negotiations that culminated in 1987 with amendments to the coal royalty and lease agreements for mining coal for the Navajo and Mohave Generating Stations. The suit alleges $600.0 million in damages and seeks treble damages along with punitive damages of not less than $1.0 billion. In March 2001, the Hopi Tribe intervened in the suit. However, the claims of both the Navajo Nation and the Hopi Tribe have been dismissed in their entirety with respect to the District. The Navajo Nation and the Hopi Tribe may appeal the dismissals.

Previously, the Navajo Nation had filed a lawsuit against the United States Government based on similar allegations. That lawsuit had been dismissed, but on appeal, it was reinstated and the Court of Appeals, in August 2001, held that the United States had breached its fiduciary duty to the Navajo Nation, and that a claim for damages was within the jurisdiction of the Court of Federal Claims. The United States subsequently sought review by the United States Supreme Court, which, in March 2003, reversed the decision of the Court of Appeals. The District does not believe that these disputes will have material adverse effects on its operations or financial condition.

Environmental – SRP is subject to numerous legislative, administrative and regulatory requirements relative to air quality, water quality, hazardous waste disposal and other environmental matters. SRP conducts ongoing environmental reviews of its properties for compliance and to identify those properties it believes may require remediation. Such requirements have resulted and will continue to result in increased costs associated with the operation of existing properties.

Indemnifications – From time to time the District enters into agreements that provide indemnifications relating to liabilities arising from or related to those agreements. Generally, a maximum obligation is not explicitly stated in the indemnifications and, therefore, the overall maximum amount of the obligations under such indemnifications cannot be reasonably estimated. Based on historical experience and evaluation of the specific indemnities, we do not believe that any material loss related to such indemnifications is likely and therefore no related liability has been recorded.

Air Quality – The federal Clean Air Act, as amended, among other things, requires reductions in sulfur dioxide and nitrogen oxide emissions from electric generating stations and regulates emissions of hazardous air pollutants by generating stations.

In December 1999, the participants in Mohave Generating Station settled a lawsuit alleging numerous and continuing violations of opacity and sulfur dioxide standards. Under the terms of the settlement, the participants must install by January 1, 2006, a sulfur dioxide scrubber and other pollution control equipment. Major plant modifications, including emissions controls, are required for continued operation as a coal-fired plant. Capital costs are estimated at $710.4 million, of which the District's share would be $142.1 million. These costs are included in the capital contingencies portion of the 2004-2009 Improvement Program. However, as discussed in *Note (10) "Regulatory Issues,"* the uncertainty in post-2005 coal and water supply have caused the Mohave participants to be unwilling to make investments necessary if Mohave operations are to extend past 2005 without an interruption.

Congress is considering new legislation, including amendments to the Clean Air Act (CAA), which could affect the cost of generating and purchasing power. While it is too early to determine whether the legislation will be enacted, and in what form, or what their effect will be, the changes may materially impact the cost of power generated at affected generating units.

The U. S. Environmental Protection Agency (EPA) is developing regulations for the control of mercury emissions from coal and oil-fired utility boilers. Regulations are scheduled to be proposed in late 2003 with a compliance date of late 2007. These regulations are expected to affect all new and existing units. The EPA has not yet determined the level of control that would be required. These regulations could affect the District's coal-fired units. The District is uncertain of the impact of the regulations, which could range from no change to the installation of new emission controls.

Congress is considering reauthorization of the Clean Air Act. In addition, EPA is implementing a number of rulemakings under the current Clear Air Act that addresses air quality emissions. The District anticipates that emission reductions at its coal-fired power plants will be required as a result. The level of reductions and costs of compliance are not known at this time but the District expects to make significant expenditures for environmental compliance.

Coal Mine Reclamation – In management's opinion, there are sufficient accruals in the accompanying combined financial statements for the District's obligation to reimburse certain coal providers for amounts due for certain coal reclamation costs. However, the District is contesting certain other coal mine reclamation costs. Neither the District's responsibility or the ultimate amount of liability, if any, can be determined at this time. Management does not believe that the outcome of these matters will have a material adverse effect on the District's financial position or results of operations.

Gas Supply – The District and other entities in Arizona have full requirements contracts with El Paso Natural Gas Company (El Paso) for the transportation of natural gas. Because of the nature of full requirements contracts, other users of the El Paso Systems, primarily in California, have no certainty of delivery, and have challenged the full requirements contracts at FERC. FERC has ordered the conversion of the full requirements contracts to contracts with fixed amounts, and has set an extended implementation date of September 1, 2003. While the outcome of this matter is unsettled, the District's available transportation for existing and planned gas generation facilities could be

substantially reduced. The financial impact of FERC's order cannot be determined, but under extreme circumstances, could be substantial including the necessity that the District interrupt electric service. The District is considering alternatives, including gas storage and taking gas transportation service from firms that have proposed new pipelines into or through Arizona, in order to mitigate the impact of an adverse outcome.

California Energy Market Issues – A number of lawsuits have been filed concerning various aspects of the California energy market. In addition, the State of California and federal authorities are conducting investigations and other proceedings concerning various aspects of the energy situation.

Because the District bought and sold power into the California energy market, the District has been drawn into many of the proceedings. However, the District was a net buyer in the California market during the time periods being scrutinized.

The State of California and others have filed various claims, alleging antitrust violations, which have now been consolidated, against many of the power suppliers to California. Two of the suppliers who were named as defendants in those matters filed cross-claims against about 30 other participants in the California energy markets, including the District, in an attempt to expand those claims to such other participants. The District is seeking to have the cross-claims dismissed and believes that the claims, as they relate to the District, are without merit.

There are two proceedings at FERC concerning potential refunds for spot market transactions in California and in the Pacific Northwest as a result of the disturbances in the California market. The District is a party to both proceedings. It is too early to tell whether FERC will order refunds in either proceeding, the amounts or collectability of any refunds, or whether FERC's orders will stand on appeal. However, the District was a net buyer in the California and Pacific Northwest markets. The District believes that the resolution of these proceedings will not have a material adverse impact on its financial position, and may have a positive impact.

Indian Matters – From time to time, SRP is involved in litigation and disputes with various Indian tribes on issues concerning regulatory jurisdiction, royalty payments, taxes and water rights, among others (see Navajo Nation Lawsuit and Air Quality above). Resolution of these matters may result in increased operating expenses.

Other Litigation – In the normal course of business, SRP is exposed to various litigation or is a defendant in various litigation matters. In management's opinion, the ultimate resolution of these matters will not have a material adverse effect on SRP's financial position or results of operations.

Self-Insurance – The District maintains various self-insurance retentions for certain casualty and property exposures. In addition, the District has insurance coverage for amounts in excess of its self-insurance retention levels. The District provides reserves based on management's best estimate of claims, including incurred but not reported claims. In management's opinion, the reserves established for these claims are adequate and any changes will not have a material adverse effect on the District's financial position or results of operations.

REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

To the Board of Directors of
Salt River Project Agricultural Improvement
and Power District, and
the Board of Governors of
Salt River Valley Water Users' Association

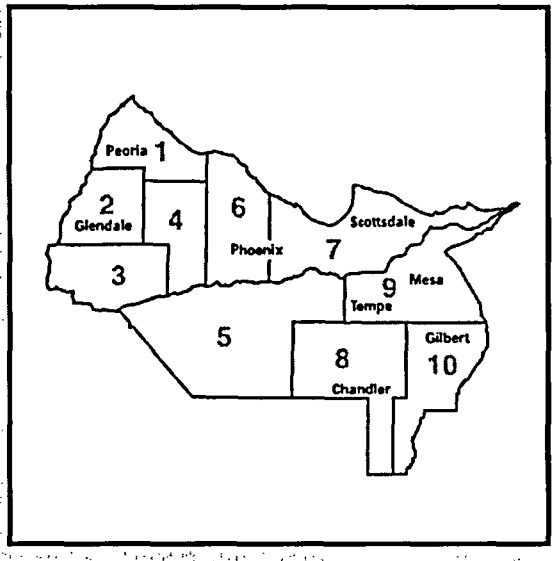
In our opinion, the accompanying combined balance sheets and the related combined statements of net revenues and comprehensive income (loss) and of cash flows present fairly, in all material respects, the financial position of Salt River Project Agricultural Improvement and Power District and its subsidiaries and Salt River Valley Water Users' Association (collectively, the Company) at April 30, 2003 and April 2002, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 3 to the combined financial statements, on May 1, 2001 the Company adopted Statement of Financial Accounting Standards No. 133 and changed its method of accounting for derivative instruments.

PricewaterhouseCoopers LLP

May 29, 2003

SRP BOARDS AND COUNCILS



SRP BOARDS

The two Boards of Salt River Project work with management to establish policies to further the business affairs of SRP.

The 10 members of the Salt River Valley Water Users' Association Board of Governors serve staggered four-year terms and are elected from voting districts by the landowners within the water service territory. The Association is SRP's private water corporation, which administers the water rights of SRP's 240,000-acre area, and operates and maintains the irrigation and drainage system.

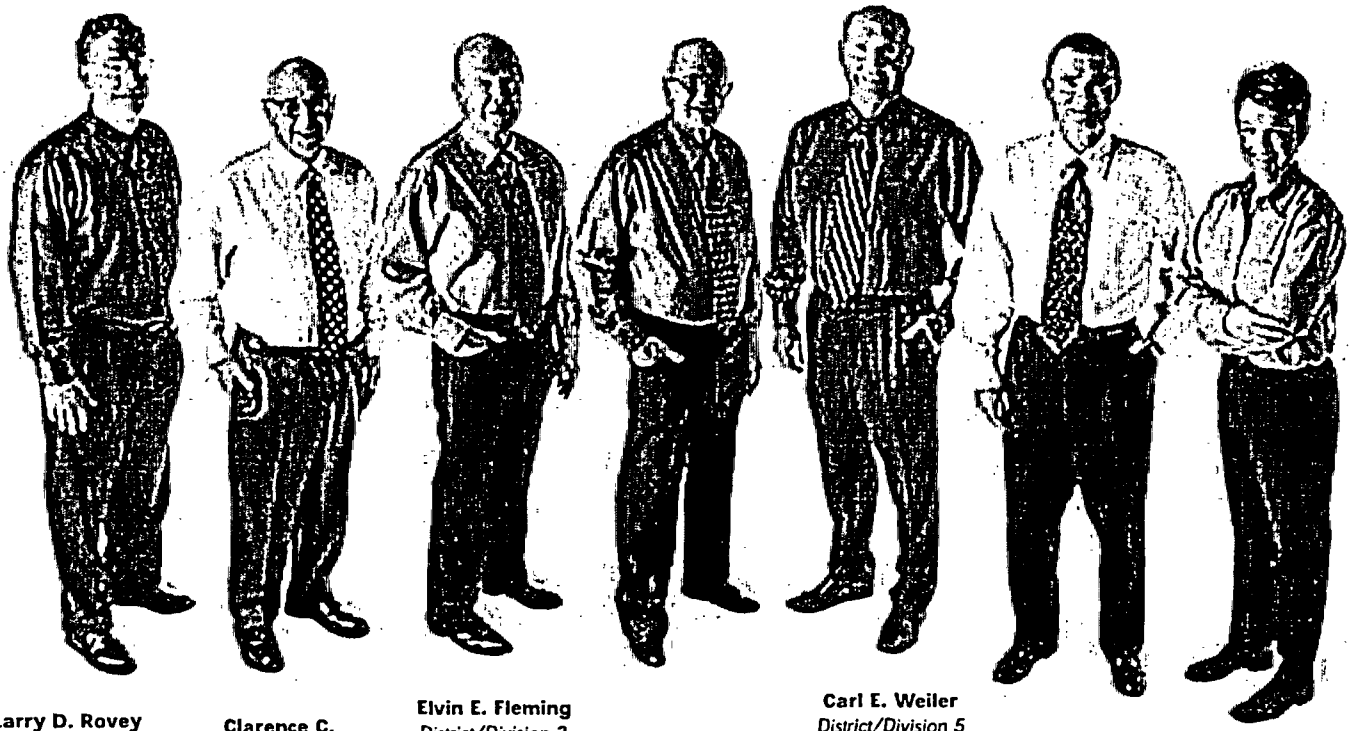
The 14 members of the Salt River Project Agricultural Improvement and Power District Board of Directors serve staggered four-year terms. Ten District Board members are elected from voting divisions and four are elected at-large by landowners within the District's boundaries. The District is SRP's public power utility and a political subdivision of Arizona. Most often, candidates seek election to both Boards.

SRP COUNCILS

The two Councils of Salt River Project enact and amend bylaws relating to business affairs of SRP and also serve as liaisons to District electors and Association shareholders.

As with the SRP Boards, there is one Council for the District and one for the Association. The 30 District Council members are elected to staggered four-year terms from 10 divisions. The 30 Association Council members are elected to staggered four-year terms from 10 districts. Most often, candidates seek election to both Councils.

BOARDS: ASSOCIATION & DISTRICT



Larry D. Rovey
District/Division 1

Clarence C. Pendergast Jr.
District/Division 2

Elvin E. Fleming
District/Division 3

Gilbert R. Rogers
District/Division 4

Carl E. Weiler
District/Division 5

John M. White Jr.
District/Division 6

Ann M. Burton
Division 7

COUNCILS: ASSOCIATION & DISTRICT

Robert L. Cook
District/Division 1

John R. Starr
District/Division 1

Kevin J. Johnson
District/Division 1

Wayne A. Hart
Vice Chairman
District/Division 2

Paul E. Rovey
District/Division 2

John A. Vanderwey
District/Division 2

Leslie C. Williams
District/Division 4

Roy W. Cheatham
District/Division 5

Wayne A. Weiler
District/Division 5

Stephen H. Williams
District/Division 5

Ben A. Butler
District/Division 6

Harmen Tjaarda Jr.
District/Division 7

Deborah S. Hendrickson
District/Division 8

John R. Hoopes
Chairman
District/Division 8

Mark L. Farmer
District/Division 8

Arthur L. Freeman
District/Division 9

Keith B. Woods
District 7

Robert G. Kempton
District/Division 8

Dale C. Riggins Jr.
District/Division 9

Dwayne E. Dobson
District/Division 10

David Rousseau
Director-at-large, seat 11

William W. Arnett
Director-at-large, seat 12

Fred J. Ash
Director-at-large, seat 13

Wendy Marshall Hancock
Director-at-large, seat 14

John E. Anderson
District/Division 3

Mario J. Herrera
District/Division 3

Robert T. Van Hofwegan
District/Division 3

Lloyd (Lee) E. Banning
District/Division 4

Charles D. Coppinger
District/Division 4

Jacqueline (Jacque) Miller
District/Division 6

Robert W. Warren
District/Division 6

Mark A. Lewis
District/Division 7

Keith B. Woods
Division 7

Ann M. Burton
District 7

W. Curtis Dana
District/Division 9

Edward E. Johnson
District/Division 9

Mark V. Pace
District/Division 10

Orland R. Hatch
District/Division 10

William P. Schrader Jr.
District/Division 10

Corporate Officers

President	William P. Schrader
Vice President	John M. Williams Jr.
Secretary	Terrill A. Lonon
Treasurer	Stephen J. Hulet

Executive Management

General Manager	Richard H. Silverman
Associate General Managers	David G. Areghini
	Mark B. Bonsall
	D. Michael Rappoport
	John F. Sullivan
	L.J. U'Ren
Corporate Counsel	Jane D. Alfano
Manager	Richard M. Hayslip

Corporate Headquarters

Street address	SRP 1521 N. Project Drive Tempe, Arizona 85281-1298
Mailing address	SRP P.O. Box 52025 Phoenix, AZ 85072-2025

SRP on the Internet

Visit SRP's home page at *www.srpnet.com* for an electronic version of this annual report.

Financial Inquiries

Dean Yee, Manager, SRP Financial Services
(602) 236-5231

Requests for Annual Reports

For additional copies of this report, call SRP at (602) 236-2598.

Bondholder Information

For all bond information, contact the SRP Treasury Department, (602) 236-2222.

Other Inquiries

Please send an email to investor@srpnet.com.

Special thanks to the following for their role in the Communities Section of this report:
Breanna Jones, Derrick Talion, Vanessa Miranda, James Jones, Shae Duensing, Glen Ali, Jessie Miranda, Jared Duensing, and Heather Jones.

SRP Two-Year Financial & Operational Review

Financial Data ($000)	2003	2002
Total operating revenues	$1,993,925	$2,214,378
Electric revenues	1,981,499	2,200,106
Water & irrigation revenues	12,426	14,272
Total operating expenses	1,829,860	2,110,121
Total other income, net	27,467	52,304
Net financing costs	138,135	148,599
Net revenues for the year	46,669	19,796
Taxes and tax equivalents	90,388	86,255
Utility plant, gross	8,191,576	7,841,713
Long-term debt	2,809,581	3,033,931
Electric revenue contributions to support water operations	44,222	32,219

Selected Data		
Debt service coverage ratio	2.23	3.09
Total electric sales (million kWh)	35,166	36,534
Peak-SRP retail customers (kW)	5,296,000	5,164,000
Water deliveries (acre-feet)**	-	1,011,214
Runoff (acre-feet)**	-	288,676
Employees at year-end	4,231	4,252
Electric customers at year-end	796,171	772,791

Includes SRP participation in jointly owned projects.

***Water data is by calendar year, all other data is by fiscal year ending April 30.*