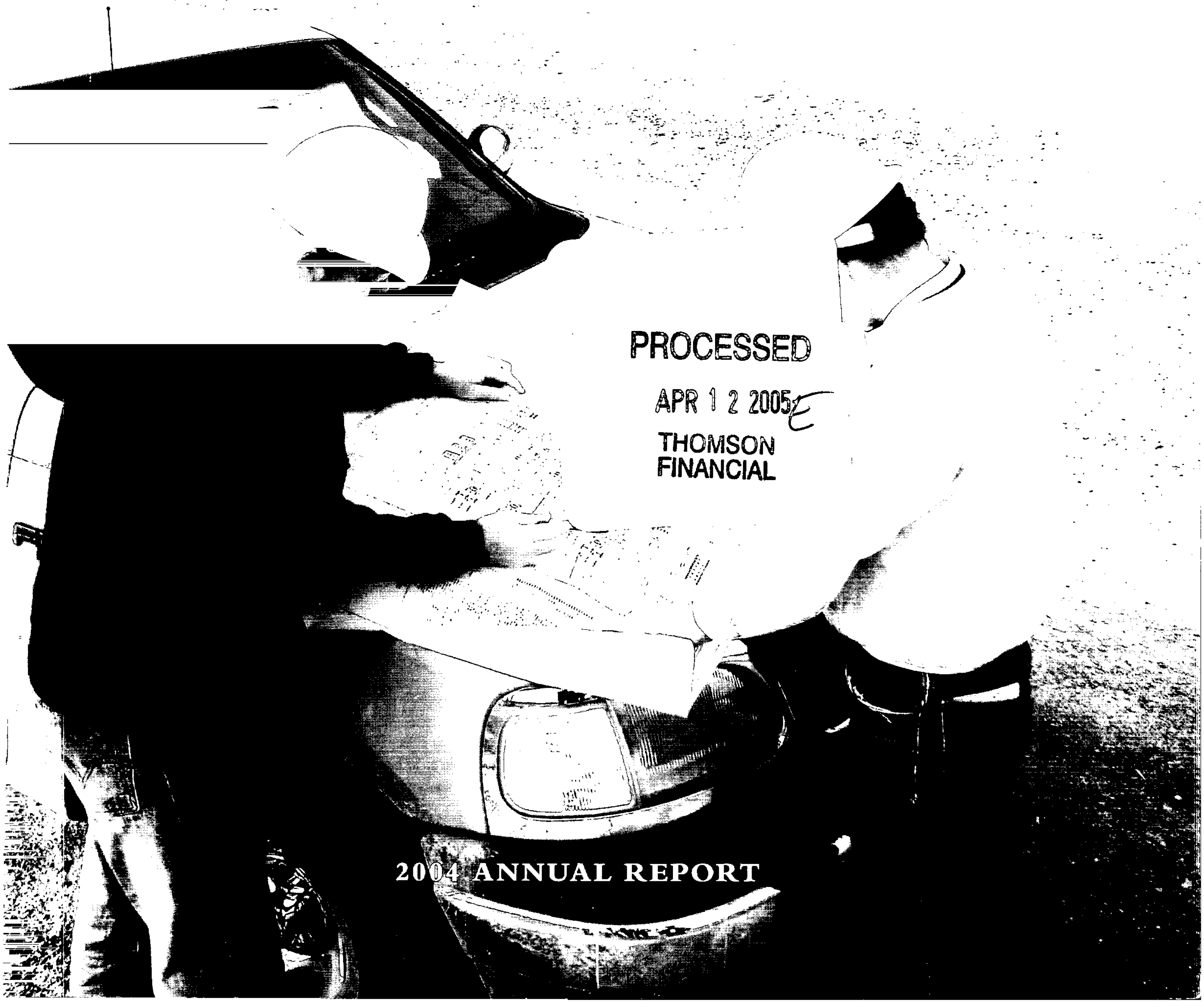
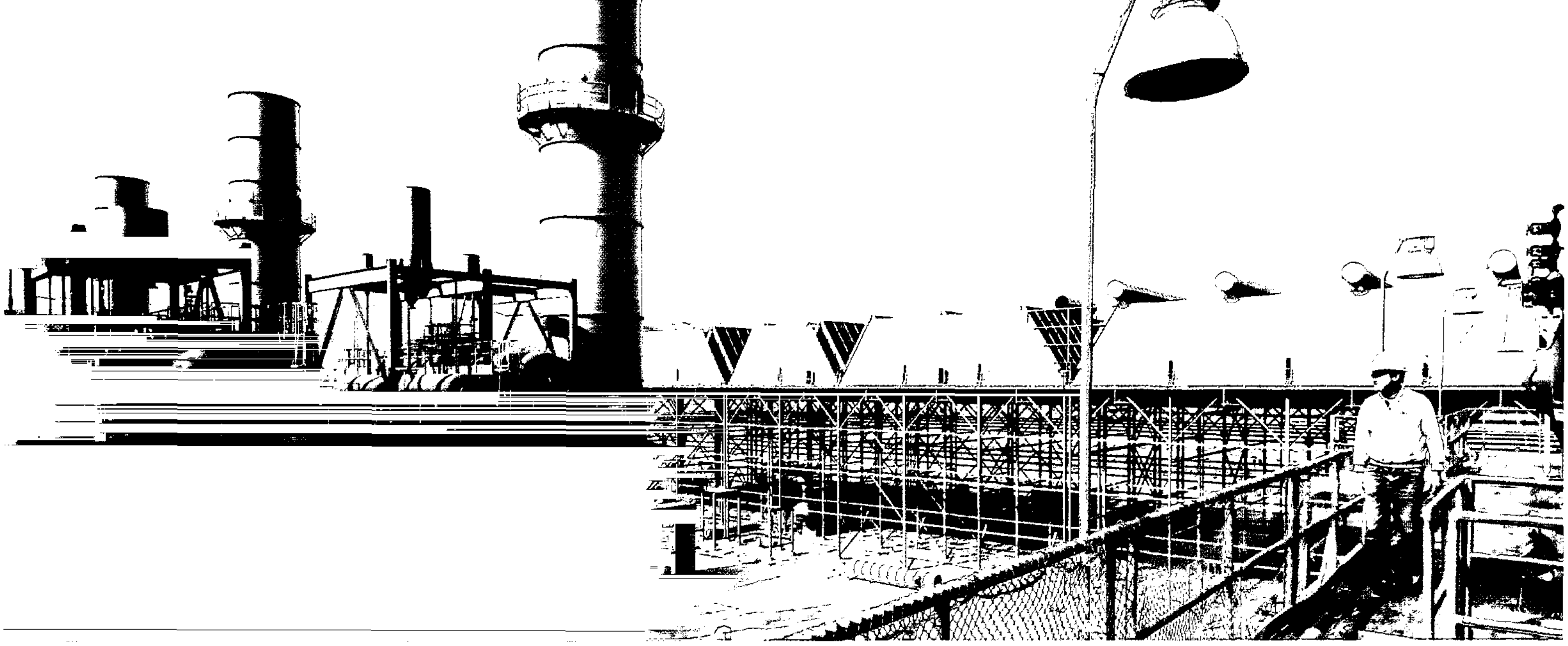
Sierra Pacific™
RESOURCES

FOCUSING ON THE FUNDAMENTALS



2004 ANNUAL REPORT



Nevada Power's Chuck Lenzie Generating Station is expected to be in full service during the first quarter of 2006.
The plant is located in the Moapa Valley, about 20 miles northeast of Las Vegas.

SIERRA PACIFIC RESOURCES IN BRIEF

Sierra Pacific Resources is an investor-owned corporation with operating subsidiaries engaged in the utility business, principally in the State of Nevada. The company's stock is traded on the New York Stock Exchange under the symbol SRP.

Chief operating subsidiaries are Nevada Power Company, which serves approximately 738,000 electric customers in Las Vegas and surrounding areas of southern Nevada; and Sierra Pacific Power Company, which has approximately 342,600 electric customers in northern Nevada and the Lake Tahoe area of northern California, and provides natural gas service to approximately 134,800 customers in the Reno-Sparks metropolitan area of northern Nevada.

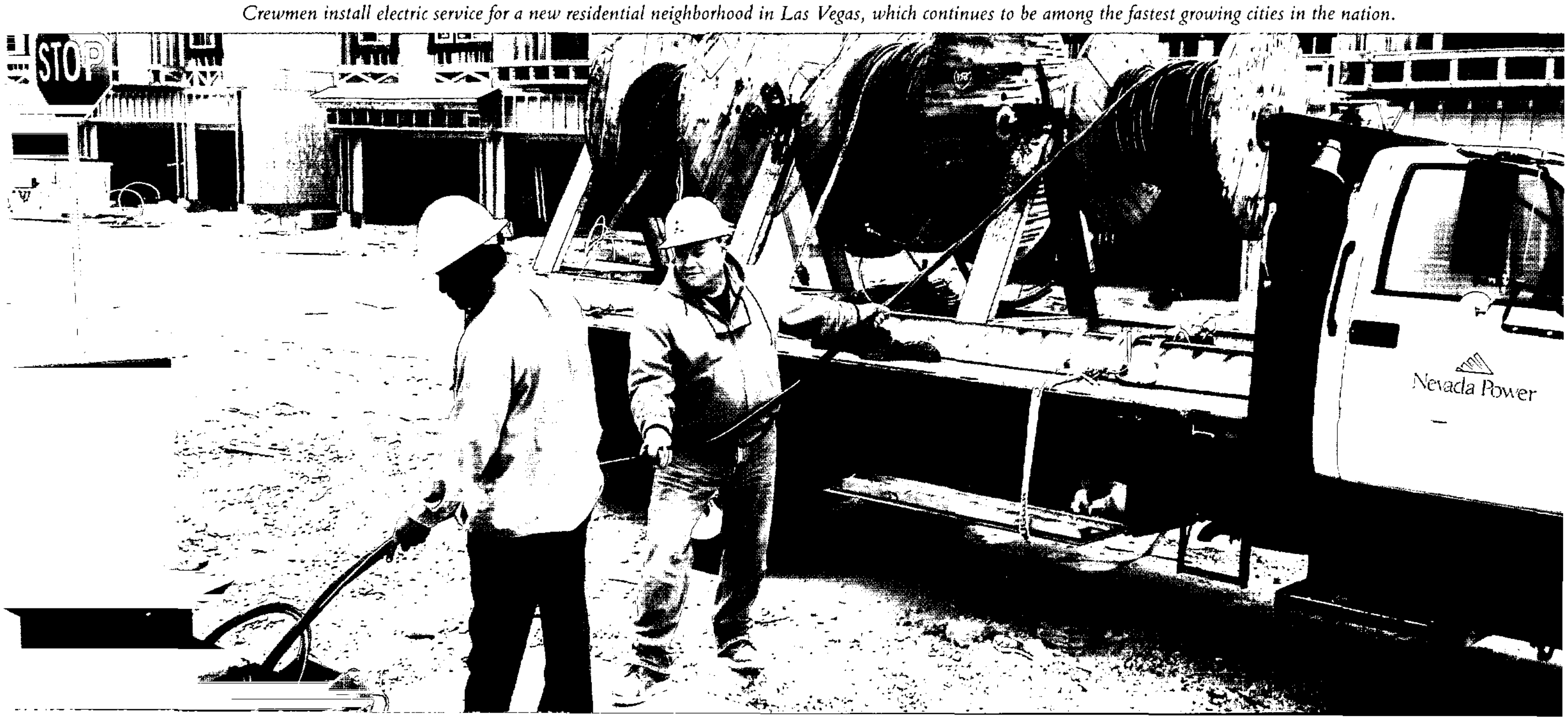
The combined service areas of the two utilities cover approximately 54,000 square miles.

Other operating subsidiaries include the Tuscarora Gas Pipeline Company, which owns a 50 percent interest in an interstate natural gas pipeline.

The number of registered holders of Sierra Pacific Resources' common stock was 20,443 as of December 31, 2004.

Cover: Work is well under way on the new natural gas-fired Chuck Lenzie Generating Station that will produce 1,200 megawatts of electricity to serve customers in southern Nevada.

Crewmen install electric service for a new residential neighborhood in Las Vegas, which continues to be among the fastest growing cities in the nation.



Sierra Pacific™
RESOURCES

HIGHLIGHTS

(dollars in thousands)	**2004**	2003
Total Operating Revenues	**$2,823,839**	$2,787,543
Total Operating Expenses	**$2,485,054**	$2,516,079
Net Income (Loss)	**$ 28,571**	$ (140,529)
Net Income (Loss) Per Share	**$ 0.16**	$ (1.21)
Weighted Average Common Shares	**183,080,475**	115,774,810
Total Assets	**$7,528,467**	$7,063,758
Total Electric Retail Sales (MWH)	**27,750,463**	26,859,806
Total Retail Gas Sales (Decatherms)	**13,896,000**	13,089,000
Total Electric Customers	**1,080,600**	1,036,771
Total Gas Customers	**134,800**	129,000

CHAIRMAN'S MESSAGE TO SHAREHOLDERS:

I am pleased to report that 2004 was a successful and pivotal year for Sierra Pacific Resources.

After several years of disappointing financial results stemming from the Western Energy Crisis of 2000–2001, your company had many noteworthy achievements and developments. While challenges remain, we are excited and enthused by financial and operating improvements signaling that we have turned the corner in moving our company toward full recovery.

First, a brief sampling of 2004 company highlights:

- Operationally, we continued to maintain our tradition of providing reliable service in the fastest-growing state in the nation while shattering prior records for new customer hookups in both southern and northern Nevada.
- Financially, we continued to strengthen our balance sheet and overall financial positioning, and returned to full-year profitability.
- Strategically, we took another step to help bring energy stability to Nevada with the acquisition of the Chuck Lenzie Generating Station now under construction near Las Vegas.
- Organizationally, we have instituted changes that will allow us to serve our marketplaces more efficiently and cost effectively, and to continue to improve our relationships with customers, regulators and other important stakeholders in the communities we serve.

In short, the basis of all our endeavors in the recent past and for the foreseeable future is to focus on the fundamentals of the utility business. Our stated company vision is:

To be a respected, customer driven, profitable electric gas and utility company operating in one of the fastest growing regions, one that is a great place to work.

Here's how and what we did to achieve that vision during 2004.

FINANCIAL RESULTS

For the full year, we reported net income of $28.6 million, or 16 cents per share, compared with a loss applicable to common stock of approximately $140.5 million, or $1.21 per share, in 2003.

Positive factors affecting 2004 earnings were strong customer growth at Nevada Power Company and Sierra Pacific Power Company, the effects of general rate case decisions by the Public Utilities Commission of Nevada, and a favorable court decision in the Enron lawsuit that resulted in a reversal of interest charges of $40 million.

A primary factor in our renewed financial health was approximately $1.8 billion of debt financing activity during 2004 in which we achieved annual interest savings of some $6 million for our utilities. Moody's rating service changed the company's outlook to stable from negative, reflecting our improved financial strength and flexibility.

SERVING THE FASTEST GROWING STATE

Nevada has been the fastest growing state in the nation for the past 18 years and keeping up with this growth has been an enormous challenge.

Nevada Power field personnel installed a record 46,549 electric meters in the Las Vegas area during the past year, while Sierra Pacific Power also experienced record growth with 11,244 electric meter sets in northern Nevada and 5,647 meters in our Reno-Sparks natural gas service area.

With this influx of new customers, peak demand for electricity has risen steadily. Nevada Power reported an all-time system peak of 4,969 megawatts on August 11, 2004. Sierra Pacific Power recorded a system peak of 1,631 megawatts last summer, only slightly below its record. On November 30, Sierra Pacific Power set an all-time, one-day peak for natural gas send out of 125.5 million cubic feet of gas.

Achieving this record growth was just one of the challenges our field personnel confronted and overcame during the past year. Forest fires in the north and severe weather conditions throughout the state also tested our mettle and resources. Fires burned through 8,700 acres near Carson City, Nevada, destroying a number of homes as well as 55 Sierra Pacific Power poles and other company facilities. This past winter, the Reno-Lake Tahoe area was hit with the biggest series of snowstorms since 1916, and Las Vegas encountered its wettest winter ever. Throughout all of these challenges, the skills and dedication of our work force resulted in comparatively few operational problems.

In other areas of operations, we are embracing new technologies to reduce costs and improve customer service. Just one example is a new Interactive Voice Response system that allows customers to complete a wide range of service transactions, such as checking account balances without speaking to a customer service representative.

EXPANDING GENERATING CAPACITY

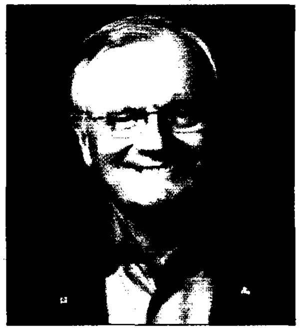
The company took a major step toward reducing its dependence on purchased power and volatile energy markets with the acquisition in October 2004 of a partially constructed 1,200 megawatt (MW) natural gas-fired, combined cycle generating plant about 20 miles northeast of Las Vegas. The Chuck Lenzie Generating Station is named in honor of Nevada Power's former chief executive officer.

Total costs to acquire and complete construction of the facility are estimated at $550 million, $182 million of which was for the purchase of the facility in its state of completion at that time.

The Public Utilities Commission of Nevada's order approving this project allows for an enhanced return on equity of 2 percent (on construction costs) plus an additional 1 percent ROE enhancement if the two generating units are brought on line before the summer of 2006. The facility currently is expected to be fully operational during the 2006 first quarter.

In November 2004, the PUCN approved programs and strategies in Sierra Pacific Power's 20-Year Electric Resource Plan, our blueprint for helping ensure that northern Nevada has adequate energy for the future.

Among the proposals that are still subject to PUCN approval is construction of a 500-MW, natural gas-fired, combined cycle generating plant at our existing Tracy Power Station site east of Reno. We'll also be assessing the expansion of coal-fired generation at our 500-MW Valmy Generating Station in northeastern Nevada. The PUCN had previously authorized Nevada Power to conduct a study on the feasibility of an environmentally acceptable coal plant to be in service as early as 2010 in southern Nevada.



Walter M. Higgins

The employees who operate our generating plants have demonstrated a remarkable commitment to safety. During the past year, Nevada Power's Clark/Sunrise/Harry Allen complex and Sierra Pacific's Tracy and Fort Churchill power stations received recognition for their exemplary safety records. At Fort Churchill, employees celebrated 18 years without a single lost-time injury, believed to be an industry-wide record.

CONTINUED GROWTH FOR RENEWABLE ENERGY

The State of Nevada has ambitious plans for developing renewable energy and we are at the forefront of this quest. Nevada Power and Sierra Pacific Power are required to increase their use of renewable energy incrementally until it accounts for 15 percent of each utility's energy sales by 2013. Solar-generated power must account for 5 percent of the total renewable energy portfolio at each utility.

Both utilities have contracted with renewable energy producers to purchase renewable energy as well as energy credits for electricity generated by solar, wind and geothermal projects in Nevada. Recently, Sierra Pacific Power agreed to buy 20 MW of electricity from a geothermal producer near Reno beginning in 2006.

While most of the renewable energy for Nevada will come from new generating plants, the utility companies' SolarGenerations program is encouraging electric customers to use solar energy at their homes and businesses. Rebates are offered as an incentive for installing photovoltaic panels on rooftops. The program has been very popular with customers.

Our energy efficiency and conservation programs have a fundamental purpose of helping customers make wise energy choices while at the same time reducing their power bills. Over the past two years, these programs have assisted customers in saving over 100,000 megawatt-hours of electricity, enough to power 6,600 homes. This has reduced summer peak demands by over 25 megawatts, the equivalent of a small power plant.

A STRONGER TRANSMISSION SYSTEM

Our electric transmission systems are being strengthened statewide. Nevada Power's massive Centennial Plan—approximately 100 miles of new high voltage transmission lines in southern Nevada—is now in the final leg of the project—a 48-mile 500,000-volt line that is expected to be finished by January 2007.

In May 2004, we completed the 180-mile, Falcon-to-Gonder transmission project in northeastern Nevada, a new 345,000-volt transmission line, increasing by 250 megawatts the amount of electricity capable of being delivered to northern Nevada and northeastern California.

REGULATORY ACTIVITIES

The company has made solid progress in improving its working relationship with state regulators and recent rate case decisions are indicative of this. During 2004, Nevada Power and Sierra Pacific Power both realized increased revenues from cases in which the PUCN approved new general rates, including the authorization of higher rates of return. Additionally, in the utilities' respective deferred rate cases in 2004, the PUCN approved rate adjustments allowing for virtually full recovery of fuel and purchased power costs.

Year 2005 has started on a good note as well. The incentive return on the construction of the Lenzie generating facility, as discussed earlier, was positive. A settlement was reached with intervenors, including the Bureau of Consumer Protection, the PUCN staff and some large customers, that allows full recovery over two years of Nevada Power's $115.9 million deferred energy filing. The PUCN unanimously approved this settlement in March 2005.

Currently pending before the PUCN is Sierra Pacific Power's request for recovery of $27.7 million in fuel and purchased power expenses incurred from December 1, 2003 through November 30, 2004. Hearings on that request are scheduled for April 2005.

BUSINESS ACCORD BENEFITS NEVADA

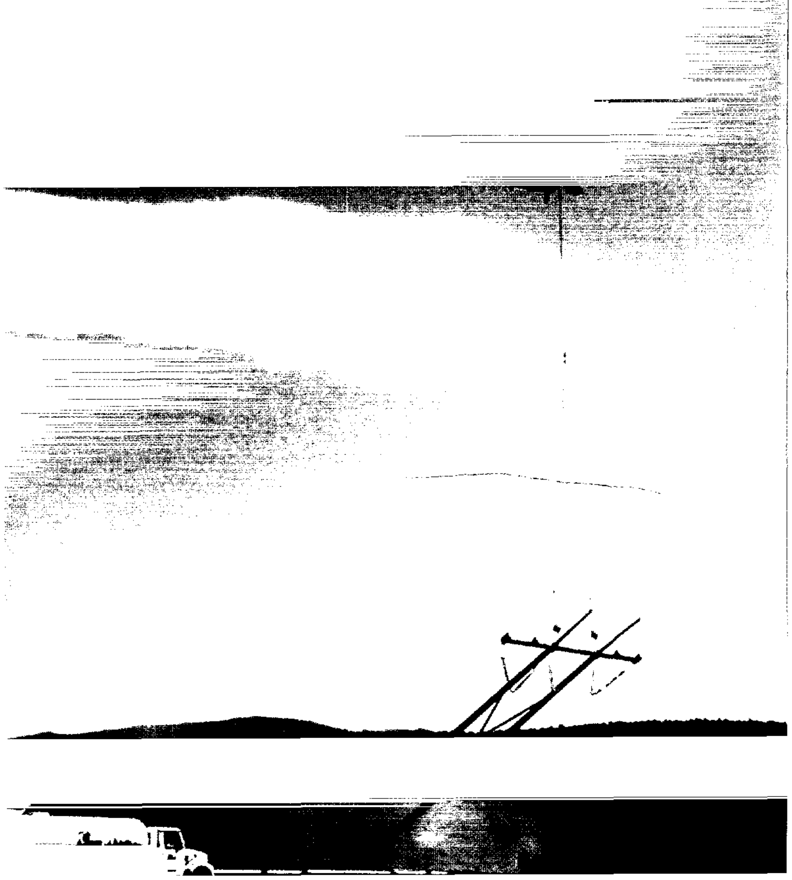
In February 2005, Nevada Power, the Colorado River Commission (CRC) and the Southern Nevada Water Authority (SNWA) agreed to work together under a cooperative business accord.

The accord will allow all three entities to collaborate on mutually beneficial initiatives while focusing on our primary missions of providing reliable electricity and water supplies for southern Nevada. Importantly, this accord resolves all outstanding issues, including legal disputes, among the entities.

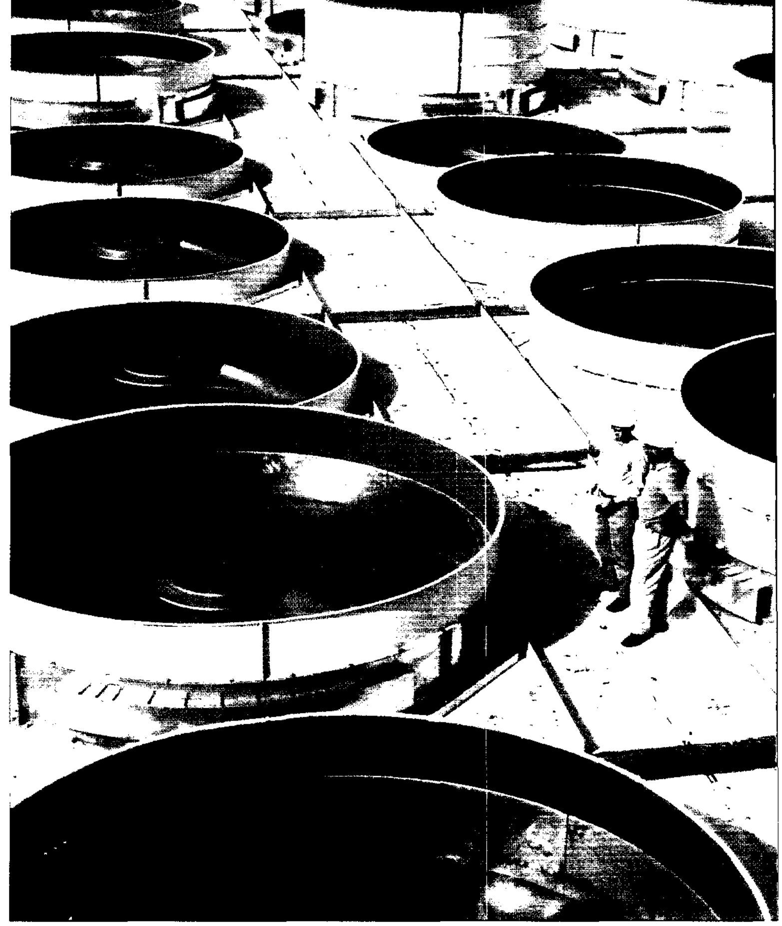
Among a number of terms of the accord, Nevada Power will enter into a long-term agreement to operate SNWA's interest in the new combined-cycle, gas-fired Silverhawk Power Plant about 35 miles northeast of Las Vegas.

ENRON DISPUTE REMAINS IN COURT

Our ongoing legal dispute with Enron, the infamous bankrupt energy company, is moving forward. In October 2004, the U.S. District Court for the Southern District of New York vacated a judgment from the Enron bankruptcy court against the company



A helicopter lifts a tower during construction of Sierra Pacific Power's Falcon-to-Gonder transmission project which was completed and placed into service in northeastern Nevada during 2004. The 345,000-volt transmission line covers 180 miles.



Fans atop one of the several geothermal power plants in northern Nevada are used to cool fluid that's heated by natural energy tapped from underneath the earth.

and remanded to the bankruptcy court for hearing the relevant facts, issues and arguments. The hearing has been scheduled to commence April 18, 2005.

On March 11, 2005, the Federal Energy Regulatory Commission (FERC) issued an order that asserts FERC's regulatory authority in the Enron contract termination matter. This bolstered our contention that FERC is the appropriate venue to resolve Enron's claims against us. FERC had scheduled a hearing to begin on June 13, 2005. However, just before publication of this report, the company was informed that the hearing will be rescheduled and is expected to be held early in September 2005.

We appreciate the strong support we have received from Nevada's entire legislative delegation in Washington, D.C., the PUCN and the Nevada Attorney General's office on these and other issues involving our company.

ORGANIZATIONAL REALIGNMENT UNDERWAY

As mentioned earlier, we are realigning our internal organization to continue to improve operations, customer service and financial performance. While our utilities retain their strong brand presence, some important functions within the overall Sierra Pacific Resources organization have been consolidated to improve efficiencies, enhance operating and administrative processes and lower operating costs. We are confident that this realignment will benefit our customers, shareholders, employees, vendors and other stakeholders.

Although we expect to complete the company's reorganization during the first quarter of 2005, this will be an ongoing process.

Early in 2005, two outstanding business and community leaders were elected to Sierra Pacific's Board of Directors: Philip G. Satre, former chairman and chief executive officer of Harrah's Entertainment Inc., and Joseph B. Anderson, Jr., chairman and chief executive officer of Michigan-based TAG Holdings Companies, which owns controlling interests in a diverse range of manufacturing and service-related enterprises. Both will be strong assets in helping guide our company.

In summary, Sierra Pacific Resources is making key additions to its overall business capabilities while, at the same time, focusing on the fundamentals of our business.

We thank you, our shareholders, for your continuing support. After successfully meeting and surmounting most of the difficulties encountered during the past few years, your company is well poised for the future. On behalf of our management team, and all of Sierra Pacific Resources employees, I can assure you that we look forward to 2005 and the years ahead with renewed vigor.

Walter M. Higgins
Chairman, President and Chief Executive Officer
March 25, 2005

SIERRA PACIFIC RESOURCES
FINANCIAL PERFORMANCE

FINANCIAL TABLE OF CONTENTS

SELECTED FINANCIAL DATA—SIERRA PACIFIC RESOURCES

See Management's Discussion and Analysis of Financial Condition and Results of Operations, for a discussion of factors that may affect the future financial condition and results of operations of SPR, NPC, and SPPC.

Year ended December 31,	**2004(4)**	2003(3)	2002(2)	2001(1)	2000
(dollars in thousands, except per share amounts)					
Operating Revenues	**$2,823,839**	$2,787,543	$2,984,604	$4,574,987	$2,325,066
Operating Income (Loss)	**$ 338,785**	$ 271,464	$ (27,509)	$ 224,641	$ 126,674
Net Income (Loss) from Continuing Operations	**$ 35,635**	$ (104,160)	$ (294,979)	$ 35,818	$ (45,264)
Income (Loss) from Continuing Operations Per Average Common Share—Basic	**$ 0.19**	$ (0.90)	$ (2.89)	$ 0.41	$ (0.58)
Income (Loss) from Continuing Operations Per Average Common Share—Diluted	**$ 0.19**	$ (0.90)	$ (2.89)	$ 0.41	$ (0.58)
Total Assets	**$7,528,467**	$7,063,758	$7,110,639	$8,132,727	$5,804,251
Long-Term Debt	**$4,081,281**	$3,579,674	$3,226,281	$3,570,750	$2,378,312
Dividends Declared Per Common Share	**$ —**	$ —	$ 0.20	$ 0.40	$ 1.00

(1) In 2001, the Utilities implemented deferred energy accounting for fuel and purchased power costs. Under deferred energy accounting, to the extent actual fuel and purchased power costs exceed fuel and purchased power costs recoverable through current rates, the excess is not recorded as a current expense on the Statement of Operations but rather is deferred and recorded as an asset on the Balance Sheet. For 2001, fuel and purchased power costs were higher than normal due to the Western Energy Crisis, and as a result, Total Assets increased significantly from the year 2000 to 2001. Additionally, Operating Revenues were significantly higher in 2001 compared to other years due to volumes of wholesale electric power to other utilities and hedging activity.

(2) Loss from Continuing Operations and Total Assets for 2002 were severely affected by the write-off of deferred energy costs and related carrying charges of $523 million as a result of the PUCN decision in NPC's and SPPC's deferred energy cases disallowing $434 million and $53 million, respectively, of deferred purchased fuel and power costs.

(3) Loss from Continuing Operations for 2003 was negatively affected by an unrealized net loss of $46.1 million on the derivative instrument associated with the issuance of SPR's $300 million Convertible Notes, $91 million write-off of deferred energy costs by NPC and SPPC, the impairment of SPC of $32.9 million and approximately $52 million of interest charges related to the Enron Litigation.

(4) Income from Continuing Operations for 2004 includes the reversal of approximately $40 million in interest charges due to the decision of the U.S. District Court on the appeal of the Enron bankruptcy judgment as discussed in Note 14, Commitments and Contingencies of the Notes to Financial Statements, and the write-off of $47.1 million in disallowed plant costs at SPPC.

SELECTED FINANCIAL DATA (continued)

SELECTED FINANCIAL DATA—NEVADA POWER COMPANY

Year ended December 31,	**2004(4)**	2003(3)	2002(2)	2001(1)	2000
(dollars in thousands)					
Operating Revenues	**$1,784,092**	$1,756,146	$1,901,034	$3,025,103	$1,326,192
Operating Income (Loss)	**$ 216,490**	$ 183,733	$ (104,003)	$ 144,364	$ 74,182
Net Income (Loss)	**$ 104,312**	$ 19,277	$ (235,070)	$ 63,405	$ (7,928)
Total Assets	**$4,883,540**	$4,210,759	$4,166,988	$4,791,261	$2,980,326
Long-Term Debt	**$2,275,690**	$1,899,709	$1,683,310	$1,802,680	$1,122,497
Dividends Declared—Common Stock	**$ 45,373**	$ —	$ 10,000	$ 33,000	$ 64,267

(1) In 2001, NPC implemented deferred energy accounting for fuel and purchased power costs. Under deferred energy accounting, to the extent actual fuel and purchased power costs exceed fuel and purchased power costs recoverable through current rates, the excess is not recorded as a current expense on the Statement of Operations but rather is deferred and recorded as an asset on the Balance Sheet. For 2001, fuel and purchased power costs were higher than normal due to the Western Energy Crisis, as a result, Total Assets increased significantly from the year 2000 to 2001. Additionally, Operating Revenues were significantly higher in 2001 and compared to other years due to volumes of wholesale electric power to other utilities and hedging activity.

(2) Net Loss and Total Assets for 2002 were severely affected by the write-off of $465 million of deferred purchased fuel and power costs and related carrying charges.

(3) Net Income for 2003 included a $46 million write-off of deferred energy costs and $36 million of interest charges related to the Enron litigation.

(4) Net Income includes the reversal of approximately $28 million in interest charges due to the decision of the U.S. District Court on the appeal of the Enron bankruptcy judgment, as discussed in Note 14, Commitments and Contingencies of the Notes to Financial Statements.

SELECTED FINANCIAL DATA—SIERRA PACIFIC POWER COMPANY

Year ended December 31,	**2004(4)**	2003(3)	2002(2)	2001(1)	2000
(dollars in thousands)					
Operating Revenues	**$1,035,660**	$1,029,866	$1,081,034	$1,547,430	$ 995,722
Operating Income	**$ 111,245**	$ 68,566	$ 55,292	$ 78,968	$ 45,409
Net Income (Loss)	**$ 18,577**	$ (23,275)	$ (13,968)	$ 22,743	$ (4,077)
Total Assets	**$2,524,320**	$2,362,469	$2,457,516	$2,760,770	$2,258,389
Long-Term Debt	**$ 994,309**	$ 912,800	$ 914,788	$ 923,070	$ 655,816
Dividends Declared—Common Stock	**$ —**	$ 18,530	$ 44,900	$ 63,000	$ 85,000

(1) In 2001, SPPC implemented deferred energy accounting for fuel and purchased power costs. Under deferred energy accounting, to the extent actual fuel and purchased power costs exceed fuel and purchased power costs recoverable through current rates, the excess is not recorded as a current expense on the Statement of Operations but rather is deferred and recorded as an asset on the Balance Sheet. For 2001, fuel and purchased power costs were higher than normal due to the Western Energy Crisis, and as a result, Total Assets increased significantly from year 2000 to 2001. Additionally, Operating Revenues were significantly higher in 2001 compared to other years due to volumes of wholesale electric power to other utilities and hedging activity.

(2) Loss from Continuing Operations for the year 2002 was severely affected by the write-off of $58 million of deferred purchased fuel and power costs and related carrying charges.

(3) Loss from Continuing Operations for the year 2003 was affected by the write-off $45 million inn June 2003 of disallowed deferred energy costs and interest charges of $16 million related to the Enron Litigation. See Overview of Major Factors Affecting Results of Operations, included in Management's Discussion and Analysis of Financial Condition and Results of Operations for further discussion.

(4) Net Income from Continuing Operations includes the reversal of approximately $12 million in interest charges due to the decision of the U.S. District Court on the appeal of the Enron bankruptcy judgment as discussed in Note 14, Commitments and Contingencies of the Notes to Financial Statements, and the write-off of $47.1 million in disallowed plant costs.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The information in this Form 10-K includes forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. These forward-looking statements relate to anticipated financial performance, management's plans and objectives for operations, business prospects, outcome of regulatory proceedings, market conditions and other matters, which may occur or be realized in the future. Words such as "anticipate," "believe," "estimate," "expect," "intend," "plan" and "objective," and other similar expressions identify those statements that are forward-looking. These statements are based on management's beliefs and assumptions and on information currently available to management. Actual results could differ materially from those contemplated by the forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with such statements, factors that could cause the actual results of Sierra Pacific Resources (SPR), Nevada Power Company (NPC), or Sierra Pacific Power Company (SPPC) to differ materially from those contemplated in any forward-looking statement include, among others, the following:

(1) a requirement to pay Enron Power Marketing, Inc. (Enron) for amounts allegedly due under terminated purchase power contracts;

(2) unfavorable rulings in rate cases filed and to be filed by NPC and SPPC (collectively, the "Utilities") with the Public Utilities Commission of Nevada (the "PUCN"), including the periodic applications to recover costs for fuel and purchased power that have been recorded by the Utilities in their deferred energy accounts, and deferred natural gas recorded by SPPC for its gas distribution business;

(3) the ability of SPR, NPC, and SPPC to maintain access to the capital markets to support their requirements for working capital, including amounts necessary to finance deferred energy costs, construction costs, and acquisition costs, particularly in the event of additional unfavorable rulings by the PUCN, a downgrade of the current debt ratings of SPR, NPC, or SPPC and/or adverse developments with respect to the Utilities' pending litigation with power and fuel suppliers;

(4) whether the Utilities will be able to continue to pay SPR dividends under the terms of their respective financing and credit agreements, the Enron Bankruptcy Court's order, their regulatory order from the PUCN, limitations imposed by the Federal Power Act and, in the case of SPPC, under the terms of SPPC's restated articles of incorporation;

(5) whether the Utilities will be able to continue to obtain fuel, power and natural gas from their suppliers on favorable payment terms, particularly in the event of unanticipated power demands (for example, due to unseasonably hot weather), sharp increases in the prices for fuel, power and/or natural gas, or a ratings downgrade;

(6) wholesale market conditions, including availability of power on the spot market, which affect the prices the Utilities have to pay for power as well as the prices at which the Utilities can sell any excess power;

(7) the final outcome of SPPC's pending lawsuit in Nevada state court seeking to reverse the PUCN's 2004 decision on SPPC's 2003 General Rate case disallowing the recovery of a portion of SPPC's costs, expenses and investment in the Piñon Pine Project;

(8) the final outcome of NPC's pending lawsuit in Nevada state court seeking to reverse portions of the PUCN's 2002 order denying the recovery of NPC's deferred energy costs;

(9) whether the Utilities will be successful in obtaining PUCN approval to recover the outstanding balance of their other regulatory assets and other merger costs recorded in connection with the 1999 merger between SPR and NPC in a future general rate case;

(10) the effect that any future terrorist attacks, wars, threats of war, or epidemics may have on the tourism and gaming industries in Nevada, particularly in Las Vegas, as well as on the economy in general;

(11) unseasonable weather and other natural phenomena, which, in addition to impacting the Utilities' customers' demand for power, can have potentially serious impacts on the Utilities' ability to procure adequate supplies of fuel or purchased power to serve their respective customers and on the cost of procuring such supplies;

(12) industrial, commercial, and residential growth in the service territories of the Utilities;

(13) the financial decline of any significant customers;

(14) the effect of existing or future Nevada, California or federal legislation or regulations affecting electric industry restructuring, including laws or regulations which could allow additional customers to choose new electricity suppliers or change the conditions under which they may do so;

(15) changes in the business or power demands of the Utilities' major customers, including those engaged in gold mining or gaming, which may result in changes in the demand for services of the Utilities, including the effect on the Nevada gaming industry of the opening of additional Indian gaming establishments in California and other states;

(16) changes in environmental regulations, laws or regulation, including the imposition of significant new limits on mercury and other emissions from coal-fired power plants;

(17) changes in tax or accounting matters or other laws and regulations to which the Utilities are subject;

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

(18) future economic conditions, including inflation rates and monetary policy;

(19) financial market conditions, including changes in availability of capital or interest rate fluctuations;

(20) unusual or unanticipated changes in normal business operations, including unusual maintenance or repairs; and

(21) employee workforce factors, including changes in collective bargaining unit agreements, the inability of NPC to enter into a new collective bargaining agreement with IBEW Local No. 396, strikes, or work stoppages.

Other factors and assumptions not identified above may also have been involved in deriving these forward-looking statements, and the failure of those other assumptions to be realized, as well as other factors, may also cause actual results to differ materially from those projected. SPR, NPC, and SPPC assume no obligation to update forward-looking statements to reflect actual results, changes in assumptions, or changes in other factors affecting forward-looking statements.

EXECUTIVE OVERVIEW

Management's Discussion and Analysis of Financial Condition and Results of Operations explains the general financial condition and the results of operations for Sierra Pacific Resources (SPR) and its two primary subsidiaries, Nevada Power Company (NPC) and Sierra Pacific Power Company (SPPC), collectively referred to as the "Utilities" (references to "we," "us," and "our" refer to SPR and the Utilities collectively), and includes the following:

- Critical Accounting Policies and Estimates
- For each of SPR, NPC, and SPPC:
  - Results of Operations
  - Analysis of Cash Flows
  - Liquidity and Capital Resources
- Energy Supply (Utilities)
- Regulatory Proceedings (Utilities)
- Recent Pronouncements

SPR's Utilities operate three regulated business segments which are NPC electric, SPPC electric, and SPPC natural gas service. The Utilities are public utilities engaged in the distribution, transmission, generation, and sale of electricity and in the case of SPPC, sale of natural gas. Other segment operations consist mainly of unregulated operations and the holding company operations. The Utilities are the principal operating subsidiaries of SPR and account for substantially all of SPR's assets and revenues. SPR, NPC, and SPPC are separate filers for SEC reporting purposes and as such this discussion has been divided to reflect the individual filers (SPR, NPC, and SPPC), except for discussions that relate to all three entities or the Utilities.

The Utilities are regulated by the Public Utilities Commission of Nevada (PUCN) and for the California service territory of SPPC, the California Public Utilities Commission (CPUC), with respect to rates, standards of service, setting of and necessity for, generation and certain transmission facilities, accounting, issuance of securities and other matters with respect to electric distribution and transmission operations. As a result of regulation, many of the fundamental business decisions of the Utilities, as well as the rate of return they are permitted to earn on their utility assets are subject to the approval of governmental agencies.

Overview of Major Factors Affecting Results of Operations

During 2004, SPR recognized earnings applicable to common stock of approximately $29 million compared to a deficit applicable to common stock of approximately $141 million for the year ending 2003. The change in earnings was primarily due to the following items (before income taxes):

- an unrealized loss of approximately $46.1 million recorded in 2003 on the derivative instrument associated with the issuance by SPR of $300 million of convertible debt;
- the write-off of disallowed deferred energy costs (excluding carrying charges) of approximately $46 million and $45 million by NPC and SPPC, respectively, recorded in 2003;
- losses in 2003 by Sierra Pacific Communications, an SPR subsidiary, due to the recognition of asset impairments of $32.9 million for SPC; and
- interest charges of approximately $40 million recognized in September 2003 in connection with the Enron judgment was reversed in 2004, based on the U.S District Court decision, as discussed in Note 14, Commitments and Contingencies of the Notes to Financial Statements.

Partially offsetting the increase in financial results during 2004 were the following charges:

- a non-cash goodwill impairment charge of approximately $11.7 million during 2004 (see Note 19, Goodwill and Other Merger Costs of the Notes to Financial Statements for further discussion);
- a non-cash charge in 2004 to write-off disallowed merger costs of approximately $5.9 million;
- charges of approximately $23.7 million during 2004 of tender fees, interest costs, and unamortized debt issuance costs associated with the early extinguishment of SPR's 8¾% Senior Unsecured Notes due 2005 (see Note 7, Long-Term Debt of the Notes to Financial Statements for further discussion); and
- a charge of approximately $47 million as a result of the PUCN's decision to disallow recovery of a portion of SPPC's costs associated with Piñon Pine (see Regulatory Proceedings (Utilities)).

Overview of Key Business Issues

This review summarizes key business issues faced by SPR and the Utilities during 2004 and issues management will continue to focus on in 2005. It is not intended to be an exhaustive discussion, nor to suggest that other issues may not arise during 2005 or thereafter. Details relating to the discussion below can be found in the Notes to the Financial Statements and elsewhere within this Management's Discussion and Analysis of Financial Condition and Results of Operations.

SPR and the Utilities were faced with several significant uncertainties at the onset of 2004, including their lawsuit and appeal against Enron as briefly described below and further detailed in Note 14, Commitments and Contingencies of the Notes to Financial Statements, whether the Utilities would be able to recover regulatory assets and previously incurred deferred fuel and purchased power costs; whether SPR and the Utilities would be able to refinance maturing long-term debt and secure additional liquidity to support operations; and whether the Utilities would have sufficient liquidity and the ability under certain restrictions to provide dividends to SPR to meet its debt service requirements.

Management addressed these uncertainties as follows:

- *Enron Litigation*—On June 5, 2002, Enron filed suit against the Utilities in its bankruptcy case in the U.S. Bankruptcy Court asserting claims against the Utilities for liquidated damages in an aggregate amount of approximately $309 million based on its termination of its power supply agreement with the Utilities and for power previously delivered to the Utilities. On September 26, 2003, the Bankruptcy Court entered a judgment (the Judgment) in favor of Enron for damages related to the termination of Enron's power supply agreement with the Utilities. The Judgment required the Utilities to pay approximately $338 million to Enron for liquidated damages and pre-judgment interest for power not delivered by Enron under the power supply contracts terminated by Enron in May 2002 and approximately $24.4 million for power previously delivered to the Utilities. To secure a stay pending appeal of the Judgment, NPC placed into escrow $235 million General and Refunding Mortgage Bond, Series H plus approximately $49 million in cash. SPPC placed into escrow $103 million in General and Refunding Mortgage Bond, Series E plus approximately $11 million in cash (see Note 14, Commitments and Contingencies of the Notes to Financial Statements). Significant developments with respect to Enron in 2004 included:
    - The Utilities reached an agreement with Enron pursuant to which neither NPC or SPPC will be required to provide any additional collateral, beyond the $60 million in cash and the Utilities' General and Refunding Mortgage Bonds that have been deposited in escrow, through the pendency of all remands and appeals of the Bankruptcy Court's decision.
    - The U.S. District Court, to which we had appealed the Judgment in 2003, vacated the Judgment, remanded the case to the Bankruptcy Court for fact-finding on several issues, and further held that pre-judgment interest should have been calculated at the present value rate, rather than at the rate of 1% per month used by the Bankruptcy Court. Based on the District Court's decision discussed above, the Utilities reversed the accrued interest included in contract termination liabilities by approximately $40 million for 2004.
    - If Enron were to obtain a final non-appealable judgment against the Utilities, management believes that the Utilities would have the means to pay any such judgment. The Utilities previously entered into a Remarketing Agreement with Enron and two investment banks as Remarketing Agents pursuant to which the Remarketing Agents have agreed to use reasonable efforts to remarket NPC's $186 million General and Refunding Mortgage Bond, Series H and SPPC's $92 million General and Refunding Mortgage Bond, Series E, which are presently held in escrow. Management believes that the Remarketing Agreement will facilitate the successful remarketing of the Bonds to satisfy the Utilities' payment obligations together with the cash in escrow in the event that the Utilities had to pay a judgment in favor of Enron.
    - In July 2004, the FERC issued an order granting our request for an expedited hearing to review Enron's termination of the energy contracts entered into between the Utilities and Enron, and hearings were scheduled to begin on December 13. On December 2, 2004, the Bankruptcy Court enjoined the Utilities from participating in FERC hearings, stating that the issues involved in the proposed FERC hearings were duplicative of what is before the Bankruptcy Court.
    - If NPC and SPPC receive unfavorable rulings with respect to the terminated supplier claims and as a result are required to pay part or all of the amounts accrued, the Utilities will pursue recovery of the amounts through future deferred energy filings. To the extent that the Utilities are not permitted to recover any portion of these costs through a deferred energy filing, the disallowed amounts would be charged to current operating expense.
- *Regulatory*—The Utilities new power and fuel procurement practices, along with risk control polices and practices, were recognized in recent PUCN decisions in which NPC recovered virtually all and SPPC recovered all of their deferred fuel and power costs.
- *Financings*—SPR and the Utilities refinanced maturing debt and issued new debt of approximately $900 million at favorable rates and terms, and the Utilities entered into credit facilities with terms through October 2007 under which they may borrow up to an aggregate of approximately $425 million.
- *Dividend Restrictions*—While the Utilities remain subject to a number of restrictions on their ability to pay dividends to SPR, management believes that these restrictions will not prohibit, and that the Utilities' cash flows will be sufficient to allow the payment of dividend amounts needed for SPR to meet its remaining debt service requirements for 2005.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

Future Business Issues

Late in 2004, management adopted a restructuring plan "SPR 2005 and Beyond." The plan is an organizational transformation designed to improve operations and financial performance and transform the culture of SPR and the Utilities. Some of the more specific objectives of the plan are to reorganize to more effectively serve our customers, improve plant reliability, earn our allowed Return on Equity (ROE) of 10.25%, and lower our operating costs. In order to achieve successful implementation, organizational changes will be necessary and certain business and operational processes will be streamlined and enhanced. Management expects to complete the reorganization in the first quarter of 2005. However, the effort to achieve the objectives of the plan will be an on-going process.

In 2004, the Utilities announced a strategy to begin reducing their exposure to volatile swings in power prices by building additional generating facilities.

- In October 2004, NPC purchased a partially constructed nominally rated 1,200 MW (megawatts) natural gas-fired combined cycle power plant from Duke Energy. NPC was able to finance the Chuck Lenzie Generating Station (Lenzie) project at lower rates than expected and the PUCN approved an additional 2% return on equity on construction costs of the facility. NPC entered into a contract with Fluor Enterprises to complete construction of the Lenzie project. The revised completion of Unit 1 of the facility is targeted for December 2005 and March 2006 is the targeted completion date for Unit 2. Total costs to acquire and complete construction of the facility are estimated at $558 million, which includes $182 million paid to Duke for the facility.
- SPPC received PUCN approval of the Integrated Resource Plan to move forward with permitting and conceptual engineering to build a 500-megawatt, natural gas-fired, combined cycle electric generating plant at the Tracy plant site, east of Reno. There will be an assessment of coal-fired generation alternatives for the Valmy Generating Station, including expansion and possible construction of a future generating unit.
- SPPC placed the Falcon-Gonder 345,000 volt electric transmission line in service in May 2004. This 180 mile transmission line allows an additional 250 megawatts of electricity to be delivered to northern Nevada and northeastern California.

In 2005 management plans to evaluate opportunities to refinance debt at lower interest rates. Management is focused on returning SPR and the Utilities credit ratings to investment grade.

Management will continue to work diligently to improve our relationships with the PUCN, including undertaking steps to address concerns expressed by the PUCN in our prior rate cases. We will continue to work closely with the staff of the PUCN to keep them apprised of developments and proactively address any potential concerns. We will also work closely with the PUCN in adhering to our risk management and fuel procurement policies designed to stabilize our risk exposure in the energy markets.

Subject to the approval by the entities' respective boards and certain governmental authorities, on February 10, 2005, NPC and its parent company SPR, the Colorado River Commission (CRC), and the Southern Nevada Water Authority (SNWA) agreed to work under a cooperative business accord. The accord is intended to allow NPC, CRC, and SNWA to collaborate on mutually beneficial initiatives while focusing on their respective primary missions of providing reliable electricity and water supplies for their customers. It also resolves outstanding issues among the entities.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

SPR prepared its consolidated financial statements in accordance with accounting principles generally accepted in the United States. In doing so, certain estimates were made that were critical in nature to the results of operations. The following discusses those significant estimates that may have a material impact on the financial results of SPR and the Utilities and are subject to the greatest amount of subjectivity. Senior management has discussed the development and selection of these critical accounting policies with the Audit Committee of SPR's Board of Directors. The following items represent critical accounting estimates that under different conditions or using different assumptions could have a material effect on the financial condition, liquidity, and capital resources of SPR and the Utilities:

Regulatory Accounting

The Utilities' retail rates are currently subject to the approval of the PUCN and, in the case of SPPC, they are also subject to the CPUC and are designed to recover the cost of providing generation, transmission and distribution services. As a result, the Utilities qualify for the application of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," issued by the Financial Accounting Standards Board (FASB). This statement recognizes that the rate actions of a regulator can provide reasonable assurance of the existence of an asset and requires the capitalization of incurred costs that would otherwise be charged to expense where it is probable that future revenue will be provided to recover these costs. SFAS No. 71 prescribes the method to be used to record the financial transactions of a regulated entity. The criteria for applying SFAS No. 71 include the following: (i) rates are set by an independent third party regulator, (ii) approved rates are intended to recover the specific costs of the regulated products or services, and (iii) rates that are set at levels that will recover costs can be charged to and collected from customers. Under federal law, wholesale rates charged by the Utilities and Tuscarora Gas Pipeline Company (TGPC) are subject to certain jurisdictional regulation, primarily by the FERC. The FERC has jurisdiction under the Federal Power Act with respect to rates, service, interconnection, accounting, and other matters in connection with the Utilities' sale of electricity for resale and interstate transmission. The FERC also has jurisdiction over the natural gas pipeline companies from which the Utilities take service.

Regulatory assets represent incurred costs that have been deferred because it is probable they will be recovered through future rates collected from customers. Regulatory liabilities generally represent obligations to make refunds to customers for previous collections for costs that are not likely to be incurred. Management regularly assesses whether the regulatory assets are probable of future recovery by considering factors such as applicable regulatory environment changes and the status of any pending or potential deregulation legislation. Although current rates do not include the recovery of all existing regulatory assets as discussed further below and in Note 1, Summary of Significant Accounting Policies of the Notes to Financial Statements, management believes the existing regulatory assets are probable of recovery. Management's judgment 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 write-off of regulatory assets would be required to be recognized as a charge or expensed in current period earnings.

Regulatory Accounting affects other Critical Accounting Policies, including Deferred Energy Accounting, Accounting for Goodwill and Merger Costs, and Accounting for Derivatives and Hedging Activities, all of which are discussed immediately below.

Deferred Energy Accounting

Under deferred energy accounting, to the extent actual fuel and purchased power costs exceed fuel and purchased power costs recoverable through current rates, the excess is not recorded as a current expense on the statement of operations but rather is deferred and recorded as an asset on the balance sheet. Conversely, a liability is recorded to the extent fuel and purchased power costs recoverable through current rates exceed actual fuel and purchased power costs. These excess amounts are reflected in adjustments to rates and recorded as revenue or expense in future time periods, subject to PUCN review. Pursuant to AB 369, Nevada Revised Statute (NRS) now provides that the PUCN may not allow the recovery of any costs for purchased fuel or purchased power "that were the result of any practice or transaction that was undertaken, managed, or performed imprudently by the electric utility." In reference to deferred energy accounting, NRS specifies that fuel and purchased power costs include all costs incurred to purchase fuel, to purchase capacity, and to purchase energy. Both Utilities are entitled under statute to utilize deferred energy accounting for their electric operations and both Utilities accumulate amounts in their deferral of energy costs accounts. The Utilities also record, and are eligible under the statute to recover, a carrying charge on such deferred balances.

The Utilities are exposed to commodity price risk primarily related to changes in the market price of electricity as well as changes in fuel costs incurred to generate electricity. See Item 7A, Quantitative and Qualitative Disclosures About Market Risk, for a discussion of the Utilities' purchased power procurement strategies, and commodity price risk and commodity risk management program. Currently, commodity price increases are recoverable through the deferred energy accounting mechanism, with no anticipated effect on earnings. However, the Utilities are subject to regulatory risk related to commodity price changes due to the fact that the PUCN may disallow recovery for any of these costs that it considers imprudently incurred.

As described in more detail under Regulatory Proceedings, Nevada Matters, on November 15, 2004, NPC filed an application with the PUCN seeking repayment for purchased fuel and power costs accumulated between October 1, 2003 and September 30, 2004 of $116 million. On February 22, 2005, the parties reached a stipulation in the case. The PUCN approved the stipulation in total on March 16, 2005. The stipulation provides for a full recovery of NPC's accumulated purchased fuel and power cost of $116 million with a carrying charge over a 24-month period beginning April 1, 2005 and is subject to approval by the PUCN. In NPC's 2003 and 2002 deferred energy cases, the PUCN disallowed $4 million and $48.1 million of the $93 million and $195.7 million requested for recovery, respectively.

As described in more detail under Regulatory Proceedings, Nevada Matters, on January 14, 2005, SPPC filed an application with the PUCN seeking repayment for purchased fuel and power costs accumulated between December 1, 2003 and November 30, 2004 of $27.7 million. Management believes all these costs were incurred prudently. However in SPPC's 2004 and 2003 deferred energy cases, the PUCN approved full recovery of purchased fuel and power costs of $42 million and disallowed $15.4 million for purchased fuel and power costs and required SPPC to repay customers approximately $29.6 million, respectively.

See Note 3, Regulatory Actions of the Notes to Financial Statements for additional discussion of the regulatory process to recover these deferred costs and description of the PUCN's disallowance of significant amounts in NPC's 2001 and SPPC's 2002 deferred energy cases.

Accounting for Goodwill and Merger Costs

The order issued by the PUCN in December 1998 approving the merger of SPR and NPC directed both NPC and SPPC to defer three categories of merger related costs for a three-year period, to be reviewed for recovery through future rates: merger transaction costs, transition costs, and goodwill costs. The deferral of these costs was intended to allow adequate time for the anticipated savings from the merger to develop. At the end of the three-year period, the order instructed the Utilities to propose an amortization period for the merger related costs and allowed the Utilities to recover the costs to the extent they are offset by merger savings.

Costs deferred as a result of the PUCN order were $325.1 million of goodwill and $62.8 million in other merger costs as of January 1, 2004. The deferred other merger costs consisted of $41.5 million of transaction and transition costs and $21.3 million of employee separation costs. Employee separation costs were comprised of $16.8 million of employee severance, relocation, and related costs, and $4.5 million of pension and postretirement benefits net of plan curtailment gains.

On March 26, 2004, the PUCN issued a decision on NPC's general rate case that included the recovery of goodwill and other merger costs allocated to NPC resulting from the merger of SPR and NPC in 1999. In its decision, the PUCN affirmed that NPC demonstrated merger savings and permitted NPC to recover approximately $4 million per year during the next two years beginning April 1, 2004, based on a forty-year amortization of NPC's total goodwill. The amount to be recovered over the next two years

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

reflects a reduction of 20% from the amounts sought by NPC, or approximately $1 million per year, due to customer satisfaction survey results that the PUCN determined required improvement. The decision requires NPC to again demonstrate in its next general rate application that merger savings continue during the test period in that case. Management expects that it will be able to demonstrate continued savings as a result of the merger as well as satisfactory customer survey results. As a result of the PUCN decision, goodwill of approximately $198 million was reclassified as a regulatory asset and then transferred from the financial statements of SPR to the financial statements of NPC as of March 31, 2004.

On May 27, 2004, the PUCN approved a settlement agreement in connection with SPPC's 2003 general rate case that permits SPPC recovery of goodwill and other merger costs assigned to SPPC's electric business. SPPC is permitted to recover approximately $2.4 million per year during the next two years beginning June 1, 2004, based on a forty-year amortization of goodwill costs. Similar to the decision reached in NPC's rate case described above, in order to continue to recover goodwill costs SPPC is required to again demonstrate in its next general rate application that merger savings continue during the test period in that case. Management expects that it will be able to demonstrate continued savings resulting from the merger. As a result of the PUCN decision, goodwill of approximately $96 million was reclassified to a regulatory asset and transferred from the financial statements of SPR to the financial statements of SPPC as of June 30, 2004.

In addition to amounts discussed above, SPR's Consolidated Balance Sheet as of December 31, 2004, included approximately $4 million of goodwill assigned to SPR's unregulated operations and $19 million assigned to SPPC's regulated gas business. SPPC expects to demonstrate in its next general rate case for the gas distribution business that savings from the merger allocable to the gas business exceed goodwill and other merger costs and, as a result, expects to recover goodwill and merger costs through future gas rates. Accordingly, management has not reviewed goodwill assigned to the gas business for impairment. However, the approximate $12 million of goodwill assigned to NPC's and SPPC's electric businesses that is not recoverable through future rates and approximately $4 million of goodwill assigned to SPR's unregulated operations were subject to impairment review under the provisions of SFAS No. 142.

As part of the impairment testing analysis, management revised certain underlying assumptions utilized in previously performed preliminary analyses that included revised cash flow forecasts, an increase in the discount rate applied to future cash flows, and other assumptions related to the outcomes of NPC's and SPPC's general rate cases. As a result of this impairment testing, SPR recorded a goodwill impairment charge related to NPC's and SPPC's electric reporting units of approximately $2 million and $10 million as a charge to other operating expenses in SPR's, NPC's and SPPC's Consolidated Statements of Operations for the quarter ended March 31, 2004. Goodwill assigned to SPR's unregulated businesses was determined not to be impaired.

We believe that the accounting estimate related to determining the fair value of goodwill, and thus any impairment, is a "critical accounting estimate" because (1) it is highly susceptible to change from period to period because it requires SPR management to make cash flow assumptions about future revenues, operating costs, and regulatory and legal contingencies; and (2) the impact that recognizing an impairment would have on the assets reported on our balance sheet as well as our net loss would be material. Management's assumptions about future revenues, operating costs, and regulatory and legal contingencies require significant judgment because actual operating results, regulatory and legal contingencies are undeterminable.

Accounting for Derivatives and Hedging Activities

SPR, NPC, and SPPC apply SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended. SFAS No. 133 requires that an entity recognize all derivatives as either assets or liabilities in the statement of financial position and measure those instruments at fair value.

Fuel and Purchased Power Contracts

In order to manage loads, resources, and energy price risk, the Utilities buy fuel and power under forward contracts. In addition to forward fuel and power purchase contracts, the Utilities also use options to manage price risk. All of these instruments are considered to be derivatives under SFAS No. 133. The risk management assets and liabilities recorded in the balance sheets of the Utilities and SPR are primarily comprised of the fair value of these forward fuel and power purchase contracts and other energy related derivative instruments.

Fuel and purchased power costs are subject to deferred energy accounting. Accordingly, the energy related risk management assets and liabilities and the corresponding unrealized gains and losses (changes in fair value) are offset with a regulatory asset or liability rather than recognized in the statements of operations and comprehensive income. Upon settlement of a derivative instrument, actual fuel and purchased power costs are recognized if they are currently recoverable or deferred if they are recoverable or payable through future rates.

The fair values of the forward contracts are determined based on quotes obtained from independent brokers and exchanges. The fair values of options are determined using a pricing model that incorporates assumptions such as the underlying commodity's forward price curve, time to expiration, strike price, interest rates, and volatility. The use of different assumptions and variables in the model could have a significant impact on the valuation of the instruments.

Accounting for Income Taxes

As of December 31, 2004, net operating losses (NOLs) were $330.5 million. The NOLs may be utilized in future periods to reduce taxes payable to the extent that SPR and the Utilities recognize taxable income.

The following table summarizes the tax NOL and credit carryforwards and associated carryforward periods, and a valuation allowance for amounts which SPR has determined that realization is uncertain (dollars in thousands):

	Deferred Tax Asset	Valuation Allowance	Net Deferred Tax Asset	Expiration Period
Federal NOL	$328,765	$ —	$328,765	2020–2023
State NOLs	1,472	—	1,472	2005–2013
Arizona coal credits	1,197	925	272	2005–2009
Total	$331,434	$925	$330,509	

At December 31, 2004, the Utilities had gross federal and state NOL carryforwards of $939.3 million and $18.1 million, respectively.

Considering all positive and negative evidence regarding the utilization of the Utilities' deferred tax assets, it has been determined that the Utilities are more likely than not to realize all recorded deferred tax assets, except for the Arizona coal credits. As such, these Arizona coal credits represent the only valuation allowance that has been recorded as of December 31, 2004.

Litigation Contingencies

Note 14, Commitments and Contingencies, in Notes to Financial Statements discusses the significant legal matters of SPR and its subsidiaries. As described in Note 14, NPC and SPPC established accrued liabilities, included in their Consolidated Balance Sheets as "Contract termination liabilities," of approximately $246 million and $94 million, respectively, for amounts claimed for liquidated damages for terminated power supply contracts and for power previously delivered to the Utilities by Enron and other suppliers. Correspondingly, pursuant to the deferred energy accounting provisions of AB 369, NPC and SPPC included approximately $240 million and $84 million of charges associated with the terminated power supply contracts, deferred for recovery in rates in future periods. If NPC and SPPC receive unfavorable rulings with respect to the terminated supplier claims and as a result are required to pay part or all of the amounts accrued, the Utilities will pursue recovery of the amounts through future deferred energy filings. To the extent that the Utilities are not permitted to recover any portion of these costs through a deferred energy filing, the disallowed amounts would be charged to current operating expense.

SPR and its subsidiaries, through the course of their normal business operations, are currently involved in a number of other legal actions, none of which has had or, in the opinion of management, is expected to have, a significant impact on its financial position or results of operations.

Environmental Contingencies

SPR and its subsidiaries are subject to federal, state and local regulations governing air and water quality, hazardous and solid waste, land use, and other environmental considerations. Nevada's Utility Environmental Protection Act requires approval of the PUCN prior to construction of major utility, generation, or transmission facilities. The United States Environmental Protection Agency (EPA), Nevada Division of Environmental Protection (NDEP), and Clark County Health District (CCHD) administer regulations involving air and water quality, solid, and hazardous and toxic waste.

SPR and its subsidiaries are subject to rising costs that result from a steady increase in the number of federal, state, and local laws and regulations designed to protect the environment. These laws and regulations can result in increased capital, operating, and other costs as a result of compliance, remediation, containment, and monitoring obligations, particularly with laws relating to power plant emissions. In addition, SPR or its subsidiaries may be a responsible party for environmental clean up at a site identified by a regulatory body. The management of SPR and its subsidiaries cannot predict with certainty the amount and timing of all future expenditures related to environmental matters because of the difficulty of estimating clean up costs and compliance and the possibility that changes will be made to the current environmental laws and regulations. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all potentially responsible parties. SPR and its subsidiaries accrue for environmental costs only when they can conclude that it is probable that they have an obligation for such costs and can reasonably determine the amount of such costs.

Note 14, Commitments and Contingencies in Notes to Financial Statements, discusses the environmental matters of SPR and its subsidiaries that have been identified, and the estimated financial effect of those matters. To the extent that (1) actual results differ from the estimated financial effects, (2) there are environmental matters not yet identified for which SPR or its subsidiaries are determined to be responsible, or (3) the Utilities are unable to recover through future rates the costs to remediate such environmental matters, there could be a material adverse effect on the financial condition and future liquidity and results of operations of SPR and its subsidiaries.

Defined Benefit Plans and Other Postretirement Plans

As further explained in Note 12, Retirement Plan and Postretirement Benefits of the Notes to Financial Statements, SPR maintains a pension plan as well as other postretirement benefit plans that provide health and life insurance for retired employees. All employees are eligible for these benefits if they reach retirement age (and meet certain service requirements) while still working for SPR or its subsidiaries. These costs are determined in accordance with the provisions of SFAS No. 87, "Employers' Accounting for Pensions," and SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions," and ultimately collected in rates billed to customers. Amounts are funded to trusts maintained for the plans. The amounts funded are then used to meet benefit payments to plan participants. SPR contributed $51.8 million and $72.2 million to its pension plan, in 2004 and 2003, respectively, and $0.2 million to the other postretirement benefits plan in both 2004 and 2003. Due to the sharp decline in United States equity markets since the third quarter of 2000, the value of a significant portion of the assets held in the plans' trusts to satisfy the obligations of the plans had decreased significantly. This decrease has been funded in the Retirement Plan as noted above. At the present time, it is not expected that any additional funding will be required in 2005 to meet the minimum funding levels defined by the Pension Benefit Guaranty Corporation.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

Pension Plans

SPR's reported costs of providing non-contributory defined pension benefits (described in Note 12, Retirement Plan and Postretirement Benefits of the Notes to Financial Statements) are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience.

For example, pension costs are impacted by actual employee demographics (including age and employment periods), the level of contributions SPR makes to the plan, and earnings on plan assets. Changes made to the provisions of the plan may also impact current and future pension costs. Pension costs may also be significantly affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets and the discount rates used in determining the projected benefit obligation and pension costs.

In accordance with SFAS No. 87, changes in pension obligations associated with these factors may not be immediately recognized as pension costs on the income statement, but generally are recognized in future years over the remaining average service period of plan participants. As such, significant portions of pension costs recorded in any period may not reflect the actual level of cash benefits provided to plan participants. For the twelve months ended December 31, 2004, 2003, and 2002, SPR recorded pension expense of approximately $28.3 million, $35.5 million, and $22.5 million, respectively, in accordance with the provisions of SFAS No. 87. Actual payments of benefits made to retirees and terminated vested employees for the twelve months ended September 30, 2004, 2003, and 2002 were $17.5 million, $17.7 million, and $30.0 million, respectively.

SPR has not made changes to pension plan provisions in 2004, 2003, and 2002 that had significant impacts on recorded pension expense. As further described in Note 12, Retirement Plan and Postretirement Benefits of the Notes to Financial Statements, SPR reduced the discount rate used in determining pension expense for the calendar year 2004 from 6.75% in 2003 to 6.00%. SPR has increased the discount rate to 6.10% and lowered the expected rate of return to 8.25% for determining the expense to be recorded in 2005. Pension costs for 2005 are expected to decrease as a result of favorable returns on assets and contributions made to the plan.

SPR's pension plan assets are primarily made up of equity and fixed income investments. Fluctuations in actual equity market returns, as well as changes in general interest rates, may result in increased or decreased pension costs in future periods. Likewise, changes in assumptions such as current discount rates and/or expected rates of return on plan assets could also increase or decrease recorded pension costs.

The following chart reflects the sensitivities associated with a change in certain actuarial assumptions by the indicated percentage. While the chart below reflects an increase in the percentage for each assumption, SPR and its actuaries expect that a decrease would impact the projected accumulated other postretirement benefit obligation (APBO) and the reported annual other postretirement pension cost (PBC) by a similar amount in the opposite direction. Each sensitivity below reflects an evaluation of the change based solely on a change in that assumption only.

Actuarial Assumption (dollars in millions)	Change in Assumption Increase/ (Decrease)	Impact on PBO Increase/ (Decrease)	Impact on PC Increase/ (Decrease)
Discount rate	1%	$(67.6)	$(8.7)
Rate of return on plan assets	1%	N/A	$(3.6)

In selecting an assumed discount rate for fiscal year 2004 pension cost, SPR considered the yield on high quality bonds as measured by Moody's Investors Service, Inc. (Moody's) Aa composite bond index. However, to select an assumed discount rate for fiscal year-end 2004 disclosures and for fiscal year 2005 pension cost, SPR's projected benefit payments were matched to the yield curve derived from a portfolio of over 500 high quality Aa bonds with yields within the 40th to 90th percentiles of these bond yields.

In selecting an assumed rate of return on plan assets, SPR considers past performance and economic forecasts for the types of investments held by the plan. The market value of SPR's plan assets has been affected by sharp declines in equity markets since the third quarter of 2000. However, investment returns on plan assets gained approximately $41.5 million in 2004 and $58 million in 2003 as a result of continued improvement in market conditions. These returns in conjunction with SPR's contributions have improved the funded status compared to prior years.

As a result of SPR's plan asset returns and funding through September 30, 2004, SPR was able to recognize a reduction in the additional minimum liability in the amount of $59.9 million, as prescribed by SFAS No. 87. The asset was recorded as an increase to common equity through Accumulated Other Comprehensive Income, and did not affect net income for 2004. The remaining charge to Accumulated Other Comprehensive Income will be adjusted each year to reflect assets and liabilities.

Other Postretirement Benefits

SPR's reported costs of providing other postretirement benefits (described in Note 12, Retirement Plan and Postretirement Benefits of the Notes to Financial Statements) are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience.

For example, other postretirement benefit costs are impacted by actual employee demographics (including age and employment periods), the level of contributions made to the plan, earnings on plan assets, and health care cost trends. Changes made to the provisions of the plan may also impact current and future other postretirement benefit costs. Other postretirement benefit costs may also be significantly affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets and the discount rates used in determining the postretirement benefit obligation and postretirement costs.

For the twelve months ended December 31, 2004, 2003, and 2002, SPR recorded other postretirement benefit expense of approximately $13.4 million, $11.4 million, and $3.1 million, respectively, in accordance with the provisions of SFAS No. 106. Actual payments of benefits made to retirees for the twelve months ended September 30, 2004, 2003, and 2002 were $8.0 million, $7.1 million, and $6.9 million respectively.

SPR has not made changes to other postretirement benefit plan provisions in 2004, 2003, and 2002 that have had any significant impact on recorded benefit plan amounts. As further described in Note 12, Retirement Plan and Postretirement Benefits of the Notes to Financial Statements, SPR has revised the discount rate in 2004, as compared to 2003, from 6.75% to 6.00%. SPR has increased the discount rate to 6.10% and lowered the expected rate of return to 8.25% for determining the expense to be recorded in 2005. However, in determining the other postretirement benefit obligation and related cost, these assumptions can change from period to period, and such changes could result in material changes to such amounts.

SPR's other postretirement benefit plan assets are primarily made up of equity and fixed income investments. Fluctuations in actual equity market returns, as well as, changes in general interest rates may result in increased or decreased other postretirement benefit costs in future periods. Likewise, changes in assumptions regarding current discount rates and expected rates of return on plan assets could also increase or decrease recorded other postretirement benefit costs.

The following chart reflects the sensitivities associated with a change in certain actuarial assumptions by the indicated percentage. While the chart below reflects an increase in the percentage for each assumption, SPR and its actuaries expect that a decrease would impact the projected accumulated other postretirement benefit obligation (APBO) and the reported annual other postretirement benefit cost (PBC) on the income statement by a similar amount in the opposite direction. Each sensitivity below reflects an evaluation of the change based solely on a change in that assumption only.

Actuarial Assumption (dollars in millions)	Change in Assumption Increase/ (Decrease)	Impact on APBO Increase/ (Decrease)	Impact on PBC Increase/ (Decrease)
Discount rate	1%	$(20.6)	$(1.9)
Health care cost trend rate	1%	$ 20.8	$ 1.9
Rate of return on plan assets	1%	N/A	$(0.5)

In selecting an assumed discount rate for fiscal year 2004 pension cost, SPR considered the yield on high quality bonds as measured by Moody's Investors Service, Inc. (Moody's) Aa composite bond index. However, to select an assumed discount rate for fiscal year-end 2004 disclosures and for fiscal year 2005 pension cost, SPR's projected benefit payments were matched to the yield curve derived from a portfolio of over 500 high quality Aa bonds with yields within the 40th to 90th percentiles of these bond yields.

In selecting an assumed rate of return on plan assets, SPR considers past performance and economic forecasts for the types of investments held by the plan. The market value of the SPR's plan assets has been affected by sharp declines in equity markets since the third quarter of 2000. However, investment returns on plan assets gained $5.2 million in 2004 and $9.7 million in 2003 as a result of improved market conditions.

Unbilled Receivables

Revenues related to the sale of energy are recorded based on meter reads, which occur on a systematic basis throughout a month, rather than when the service is rendered or energy is delivered. At the end of each month, the energy delivered to the customers from the date of their last meter read to the end of the month is estimated and the corresponding unbilled revenues are calculated. These estimates of unbilled sales and revenues are based on the ratio of billable days versus unbilled days, amount of energy procured and generated during that month, historical customer class usage patterns and the Utilities' current tariffs. Customer accounts receivable as of December 31, 2004, include unbilled receivables of $83 million and $67 million for NPC and SPPC, respectively. Customer accounts receivable as of December 31, 2003 include unbilled receivables of $63 million and $56 million for NPC and SPPC, respectively.

SIERRA PACIFIC RESOURCES

RESULTS OF OPERATIONS

Sierra Pacific Resources (Holding Company) and Other Subsidiaries

SPR (Holding Company)

The Holding Company's (stand-alone) operating results included approximately $88.3 million, $75.3 million, and $71.5 million of interest costs for the years ended December 31, 2004, 2003, and 2002, respectively. The holding company's operating results for 2004 were negatively affected by an impairment of goodwill of approximately $11.7 million and higher interest costs. The Holding Company recognized charges of approximately $23.7 million during 2004 for tender fees, interest costs and unamortized debt issuance costs associated with the early extinguishment of SPR's 8¾% Senior Unsecured Notes due 2005. See Note 7, Long-Term Debt of the Notes to Financial Statements, for further discussion on the early extinguishment of the debt. The Holding Company's operating results for 2003, were negatively affected by an unrealized net loss of $46.1 million on the derivative instrument associated with the convertible note debt. This unrealized loss has no effect on cash flows. See Note 7, Long-Term Debt of the Notes to Financial Statements, for further discussion on the Convertible Notes.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

Tuscarora Gas Pipeline Company

TGPC, a wholly owned subsidiary of SPR, contributed $5.2 million in net income for the year ended December 31, 2004, $3.9 million in net income for the year ended December 31, 2003, and $3.3 million in net income for the year ended December 31, 2002.

Sierra Pacific Communications

SPC, a wholly owned subsidiary of SPR, which is reported as discontinued operations, incurred a net loss of $3.2 million for the year ended December 31, 2004, a net loss of $25.2 million for the year ended December 31, 2003, and a net loss of $5.9 million for the year ended December 31, 2002. SPC's loss in 2004 was primarily due to the settlement with Sierra Touch America, see Note 18, Discontinued Operations and Disposal and Impairment of Long-Lived Assets of the Notes to Financial Statements for further discussion. SPC's increased loss for the year ended December 31, 2003 was due to the impairment charge of $32.9 million in the second quarter of 2003. SPC's increased loss for the year ended December 31, 2002, was due to interest charges and other costs associated with its exit from Sierra Touch America LLC, including the $2.3 million write-off of an uncollectible receivable.

Other Subsidiaries

Other Subsidiaries of SPR did not contribute materially to the consolidated results of operations of SPR.

Sierra Pacific Resources (Consolidated)

See Executive Overview, Results of Operations for SPR Consolidated.

ANALYSIS OF CASH FLOWS

SPR's consolidated net cash flows increased during 2004, when compared to 2003, due mainly to almost $300 million in additional debt, and rate increases to recover deferred energy balances and operating costs. A major portion of the new debt was for the purchase of the partially constructed Lenzie project from Duke Energy. This purchase is reflected in the increase in net cash used by investing activities, which was offset by cash received upon the disposal of property belonging to SPR's unregulated subsidiaries, SPC and Lands of Sierra (LOS). Cash flows from operating activities were higher during 2004 as a result of rate increases that went into effect in the second quarter of 2004, offset by higher interest payments, pension plan funding and the payment of $61 million to the Enron escrow account ordered by the judge overseeing the bankruptcy proceedings of Enron.

SPR's consolidated net cash flows decreased during 2003, when compared to 2002, as a result of a decrease in cash from operating activities that was offset in part by an increase in cash flows from financing activities and a decrease in net cash used by investing activities. Cash flows from operating activities during 2003 were lower primarily due to an income tax refund received in 2002, higher interest costs paid in 2003 and the prepayment and accelerated payment of fuel and energy purchases in 2003. Partially offsetting these items was additional cash provided from the collection of previously deferred fuel and energy costs through deferred energy rate increases and lower energy costs in 2003. Cash used by investing activities showed a reduction in 2003 because of reduced investments by SPR in its unregulated subsidiary, SPC, and a decrease in cash utilized for construction activities in 2003. Cash flows from financing activities increased during 2003 because of cash provided from short-term financings and the suspension of dividend payments by SPR.

LIQUIDITY AND CAPITAL RESOURCES (SPR CONSOLIDATED)

SPR, on a stand-alone basis, had cash and cash equivalents of approximately $3.4 million at December 31, 2004, which does not include restricted cash and investments of approximately $21.7 million. The $21.7 million represents collateral for payment of interest up to and including August 14, 2005 in connection with SPR's 7.25% Convertible Notes due 2010. Excluding interest on SPR's 7.25% Convertible Notes, SPR has approximately $50.5 million payable of debt service obligations for 2005.

Dividends from Subsidiaries

Since SPR is a holding company, substantially all of its cash flow is provided by dividends paid to SPR by NPC and SPPC on their common stock, all of which is owned by SPR. Since NPC and SPPC are public utilities, they are subject to regulation by state utility commissions, which impose limits on investment returns or otherwise impact the amount of dividends that the Utilities may declare and pay. In addition, certain agreements entered into by the Utilities set restrictions on the amount of dividends they may declare and pay and restrict the circumstances under which such dividends may be declared and paid. The specific agreements entered into by the Utilities, restrictions on dividends contained in agreements to which NPC and SPPC are party, as well as specific regulatory limitations on dividends, are summarized below and detailed in Note 9, Dividend Restrictions of the Notes to Financial Statements.

Agreements Imposing Dividend Restrictions on Nevada Power Company:

- NPC's Indenture of Mortgage, between NPC and Deutsche Bank Trust Company Americas, as trustee (the "First Mortgage Indenture")
- NPC's General and Refunding Mortgage Notes, Series E, Series G, Series I, Series L, and Series H Bond
- NPC's Revolving Credit Agreement established in connection with the purchase of Lenzie
- NPC's preferred trust securities

Agreements Imposing Dividend Restrictions on Sierra Pacific Power Company:

- SPPC's Revolving Credit Agreement
- SPPC's General and Refunding Mortgage Notes, Series H, and Series E Bond
- SPPC's Articles of Incorporation

Dividend Restrictions Applicable to Both Utilities:

- *PUCN Orders*—NPC Docket 04-1014 and SPPC Docket 03-12030, which expires on December 31, 2005, limits NPC and SPPC to annually dividend an aggregate of either SPR's actual cash requirements for debt service, or $70 million, whichever is less.
- The Bankruptcy Court's order limiting the Utilities dividends to SPR for SPR's current operating expenses and debt payment obligations. Although the judgment has been reversed by the U.S. District Court of the Southern District of New York, this limitation will remain in place pursuant to the terms of a stipulation and agreement among the Utilities and Enron.
- The Federal Power Act, which prohibits the payment of dividends from "capital accounts."

Assuming that NPC and SPPC meet the requirements to pay dividends under the Federal Power Act and that any dividends paid to SPR are for SPR's debt service obligations and current operating expenses, the most restrictive of the dividend restrictions applicable to the Utilities individually can be found for NPC, in NPC's Series E Notes and, for SPPC, in SPPC's Series H Notes, Series E Bond and its Revolving Credit Agreement. Under these restrictions (as described in Note 9, Dividend Restrictions of the Notes to Financial Statements), NPC or SPPC, as the case may be, must meet a fixed charge coverage ratio of at least 1.75:1 over the prior four fiscal quarters as a condition to their payment of dividends. Although each Utility currently meets these tests at December 31, 2004, a significant loss by either Utility could cause that Utility to be precluded from paying dividends to SPR until such time as that Utility again meets the coverage test. The dividend restriction in the PUCN order may be more restrictive than the individual dividend restrictions if dividends are paid from both Utilities because the PUCN dividend restriction of either SPR's actual cash requirements for debt service, or $70 million, whichever is less, may be less than the aggregate amount of the Utilities' individual dividend restrictions. In 2004, SPR received $45 million in dividends from NPC to meet debt service obligations.

Financing Transactions (SPR—Holding Company)

SPR Senior Unsecured Notes

On March 19, 2004, SPR issued and sold $335 million 8⅝% Senior Unsecured Notes due March 15, 2014. The SPR Senior Unsecured Notes, which were issued with registration rights, were exchanged for registered notes in October 2004. The proceeds of the issuance were used to fund the repurchase of approximately $174 million in principal amount of SPR's 8¾% Notes due 2005 at a price equal to approximately 107.225% of the principal amount thereof that were tendered pursuant to SPR's tender offer.

The balance of the net proceeds were used on May 21, 2004 to legally extinguish the approximately $126 million of remaining principal amount of SPR's 8¾% Notes due 2005 which were not tendered, and to pay associated interest and fees and expenses associated with the tender offer and the Notes offering. The total cost to extinguish the debt was approximately $23.7 million consisting of tender fees, interest costs, and unamortized debt issuance costs.

The terms of the SPR Senior Notes restrict SPR and any of its Restricted Subsidiaries (NPC and SPPC) from incurring any additional indebtedness unless:

(1) at the time the debt is incurred, the ratio of consolidated cash flow to fixed charges for SPR's most recently ended four quarter period on a pro forma basis is at least 2.0 to 1, or

(2) the debt incurred is specifically permitted under the terms of the SPR Senior Notes, which permits the incurrence of certain credit facility or letter of credit indebtedness, obligations incurred to finance property construction or improvement, indebtedness incurred to refinance existing indebtedness, certain intercompany indebtedness, hedging obligations, indebtedness incurred to support bid, performance or surety bonds, and certain letters of credit supporting SPR's or any Restricted Subsidiary's obligations to energy suppliers, or

(3) the indebtedness is incurred to finance capital expenditures pursuant to NPC's 2003 Integrated Resource Plan and SPPC's 2004 Integrated Resource Plan.

If the SPR Senior Notes are upgraded to investment grade by both Moody's and S&P, these restrictions will be suspended and will no longer be in effect so long as the series of Notes remains investment grade.

Among other things, the SPR Senior Notes also contain restrictions on liens (other than permitted liens, which include liens to secure certain permitted debt) and certain sale and leaseback transactions. In the event of a change of control of SPR or any of its Restricted Subsidiaries, the holders of these securities are entitled to require that SPR repurchase their securities for a cash payment equal to 101% of the aggregate principal amount plus accrued and unpaid interest.

Accounts Receivable Facility

On October 29, 2002, NPC and SPPC established accounts receivable purchase facilities of up to $125 million and $75 million, respectively. On May 4, 2004, each company delivered a notice of termination of its accounts receivable facility in connection with the establishment of their revolving credit facilities. The terminations were effective on May 19, 2004.

Financial Covenants

Nevada Power Company and Sierra Pacific Power Company

Each of NPC's $350 million Revolving Credit Agreement, as amended and restated on October 22, 2004, and SPPC's $75 million Revolving Credit Agreement dated October 22, 2004, contains two financial maintenance covenants. The first requires that the Utility maintain a ratio of consolidated indebtedness to consolidated capital, determined as of the last day of each fiscal quarter, not to exceed 0.68 to 1. The second requires that the Utility maintain a ratio of consolidated cash flow to consolidated interest expense, determined as of the last day of each fiscal quarter for the period of four consecutive fiscal quarters, not to be less than 2.0 to 1.

Due to a negative pledge obligation in SPPC's $92 million General and Refunding Mortgage Bond, Series E, SPPC amended its Series E Bond to include these two financial maintenance covenants. SPPC's Series E Bond, which is currently held by an

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

escrow agent, was issued to secure the Enron Judgment (see Note 14, Commitments and Contingencies of the Notes to Financial Statements for a discussion of the Enron Judgment). Although the Judgment was vacated in a decision handed down on October 10, 2004 by the U.S. District Court for the Southern District of New York, the Series E Bond will continue to remain in escrow through the pendency of all remands and appeals pursuant to a stipulation and agreement previously entered into among NPC, SPPC, and Enron.

Cross-Default Provisions

None of the financing agreements of either of the Utilities contain a cross-default provision that would result in an event of default by that Utility upon an event of default by SPR or the other Utility under any of its financing agreements. Certain of SPR's financing agreements, however, do contain cross-default provisions that would result in event of default by SPR upon an event of default by the Utilities under their respective financing agreements. In addition, certain financing agreements of each of SPR and the Utilities provide for an event of default if there is a failure under other financing agreements of that entity to meet payment terms or to observe other covenants that would result in an acceleration of payments due. Most of these default provisions (other than ones relating to a failure to pay other indebtedness) provide for a cure period of 30-60 days from the occurrence of a specified event, during which time SPR or the Utilities may rectify or correct the situation before it becomes an event of default. The primary cross-default provisions in SPR's and the Utilities' various financing agreements are briefly summarized below:

- The indentures pursuant to which SPR issued its 7.25% Convertible Notes due 2010 and its 8⅝% Senior Notes due 2014 provide for an event of default if SPR or any of its significant subsidiaries (NPC and SPPC) fail to pay indebtedness in excess of $10 million or has any indebtedness of $10 million or more accelerated and declared due and payable for so long as the 7.25% Convertible Notes are outstanding;
- NPC's General and Refunding Mortgage Indenture, under which NPC has $1.3 billion of securities outstanding (excluding NPC's Series H Bond, which is held in escrow in connection with the Enron litigation) as of December 31, 2004, provides for an event of default if a matured event of default under NPC's First Mortgage Indenture occurs;
- The terms of NPC's Series E Notes, Series G Notes, Series I Notes, Series L Notes, and Series H Bond provide that a default with respect to the payment of principal, interest, or premium beyond the applicable grace period under any mortgage, indenture, or other security instrument, by NPC or any of its restricted subsidiaries, relating to debt in excess of $15 million, triggers a right of the holders of each series of Notes, and the Bonds to require NPC to redeem their series of Notes or the Bonds at a price equal to 100% of the aggregate principal amount plus accrued and unpaid interest and liquidated damages, if any, upon notice given by at least 25% of the outstanding noteholders for such series of Notes or Bonds;
- NPC's $350 million Credit Agreement provides for an event of default if NPC defaults in the payment of principal, interest, or premium beyond the applicable grace period under any mortgage, indenture, or other security instrument, relating to debt in excess of $15 million. Upon an event of default, the Administrative Agent under the NPC Credit Agreement may, upon request of more than 50% of the lenders under the Credit Agreement, declare all amounts due under the Credit Agreement immediately due and payable. Since NPC's obligations under the Credit Agreement are secured by its General and Refunding Mortgage Bond, if NPC fails to repay all amounts due upon an acceleration of the Credit Agreement within three business days, such failure will be deemed a default in the payment of principal and will trigger an event of default under NPC's General and Refunding Mortgage Indenture that would be applicable to all securities issued under NPC's General and Refunding Mortgage Indenture;
- SPPC's General and Refunding Mortgage Indenture, under which SPPC has $420 million of securities outstanding (excluding SPPC's Series E Bond, which is held in escrow in connection with the Enron litigation) as of December 31, 2004, provides for an event of default if a matured event of default under SPPC's First Mortgage Indenture occurs;
- The terms of SPPC's Series H Notes and Series E Bond provide that a default with respect to the payment of principal, interest, or premium beyond the applicable grace period under any mortgage, indenture, or other security instrument, by SPPC or any of its restricted subsidiaries, relating to debt in excess of $15 million, triggers a right of the holders of the Series H Notes and the Series E Bond to require SPPC to redeem their series of Notes or Bonds, at a price equal to 100% of the aggregate principal amount plus accrued and unpaid interest and liquidated damages, if any, upon notice given by at least 25% of the outstanding noteholders for such series of Notes or Bonds; and
- SPPC's $75 million Credit Agreement provides for an event of default if SPPC defaults in the payment of principal, interest, or premium beyond the applicable grace period under any mortgage, indenture, or other security instrument, relating to debt in excess of $15 million. Upon an event of default, the Administrative Agent under the SPPC Credit Agreement may, upon request of more than 50% of the lenders under the Credit Agreement, declare all amounts due under the Credit Agreement immediately due and payable. Since SPPC's obligations under the Credit Agreement are secured by its General and Refunding Mortgage Bond, if SPPC fails to repay all amounts due upon an acceleration of the Credit Agreement within three business days, such failure will be deemed a default in the payment of principal and will trigger an event of default under SPPC's General and Refunding Mortgage Indenture that would be applicable to all securities issued under SPPC's General and Refunding Mortgage Indenture.

Judgment Related Defaults

Nevada Power Company

NPC's First Mortgage Indenture provides for an event of default if a final, unstayed judgment in excess of $25,000 is rendered against NPC and remains undischarged for 60 days. Upon a matured event of default, the trustee may, and upon the written request of the holders of at least 25% of the bonds outstanding under NPC's First Mortgage Indenture, is required to declare the principal of and interest on the approximately $372.5 million of outstanding First Mortgage bonds immediately due and payable.

The terms of NPC's $250 million Series E, $350 million Series G, $130 million Series I, and $250 million Series L General and Refunding Mortgage Notes, $186 million Series H General and Refunding Mortgage Bond and $350 million Revolving Credit Facility, provide for an event of default if a final, unstayed judgment in excess of $15 million is rendered against NPC and remains undischarged for 60 days. Since the Series E, Series G, Series I and Series L Notes, and Series H Bond were issued under NPC's General and Refunding Mortgage Indenture and NPC's Revolving Credit Facility is secured by a General and Refunding Mortgage Bond, a default under any of the Series E, Series G, Series I and Series L Notes, Series H Bond and Revolving Credit Facility will trigger a default under NPC's General and Refunding Mortgage Indenture.

In addition, a matured event of default under NPC's First Mortgage Indenture will trigger a default under NPC's General and Refunding Mortgage Indenture. Upon a matured event of default under the NPC's General and Refunding Mortgage Indenture, the trustee or the holders of 33% of the General and Refunding Mortgage securities outstanding may declare the principal and accrued interest of the approximately $1.3 billion of outstanding General and Refunding Mortgage securities (excluding NPC's Series H Bond, which is held in escrow) as of December 31, 2004, immediately due and payable.

If a judgment lien is created on NPC's real property located in Nevada, NPC has been advised that the judgment lien would be an interceding lien that would have priority over subsequent advances under NPC's General and Refunding Mortgage Indenture; therefore, NPC would be unable to provide certain required opinions of counsel to issue additional securities under its General and Refunding Mortgage Indenture until the judgment lien is discharged and released. Since NPC is unable to issue additional bonds under its First Mortgage Indenture, its sole means of issuing secured debt is through its General and Refunding Mortgage Indenture.

If NPC's indebtedness under either its First Mortgage Indenture or its General and Refunding Mortgage Indenture is accelerated, or if NPC is unable to issue additional securities under its General and Refunding Mortgage Indenture in order to raise funds for operations and to repay indebtedness and to provide security, as needed, for its obligations, NPC would likely be unable to continue to operate outside of bankruptcy.

Sierra Pacific Power Company

SPPC's Series E Bond, Series H Notes, and $75 million Revolving Credit Agreement provide for an event of default if a judgment of $15 million or more is entered against SPPC and such judgment is not paid, discharged, or stayed for a period of 60 days. The Notes, the Bond, and Revolving Credit Agreement also prohibit the creation or existence of any liens on SPPC's properties except for liens specifically permitted under the terms of Notes, the Bond, or Revolving Credit Agreement.

Since the Series E Bond and Series H Notes were issued under SPPC's General and Refunding Mortgage Indenture and SPPC's Revolving Credit Agreement is secured by a General and Refunding Mortgage Bond, a default under these Notes, the Bond, or the Revolving Credit Agreement will trigger a default under SPPC's General and Refunding Mortgage Indenture. In the event that a triggering event occurs that effectively accelerates the outstanding amounts due under the securities issued under the General and Refunding Mortgage Indenture, SPPC would likely be unable to continue to operate outside of bankruptcy.

If a judgment lien is created on SPPC's real property located in Nevada, SPPC has been advised that the judgment lien would be an interceding lien that would have priority over subsequent advances under SPPC's General and Refunding Mortgage Indenture; therefore, SPPC would be unable to provide certain required opinions of counsel to issue additional securities under its General and Refunding Mortgage Indenture until the judgment lien is discharged and released. Since SPPC is unable to issue additional bonds under its First Mortgage Indenture, its sole means of issuing secured debt is through its General and Refunding Mortgage Indenture. If SPPC is unable to issue additional securities under its General and Refunding Mortgage Indenture in order to raise funds for operations and to repay indebtedness and to provide security, as needed, for its obligations, SPPC would likely be unable to continue to operate outside of bankruptcy.

Pension Plan Matters

SPR has a qualified pension plan that covers substantially all employees of SPR, NPC, and SPPC. The annual net benefit cost for the plan will decrease for 2005 by approximately $5.6 million over the 2004 cost of $28.3 million. As of September 30, 2004, the measurement date, the plan was fully funded. During 2004, SPR and the Utilities contributed a total of $50.5 million to meet their funding obligations under the plan. At the present time it is not expected that any additional funding will be required in 2005 to meet the minimum funding levels defined by the Pension Benefit Guaranty Corporation.

Effect of Holding Company Structure

As of December 31, 2004, SPR (on a stand-alone basis) has a substantial amount of outstanding debt and other obligations including, but not limited to: $240 million of its unsecured 7.93% Senior Notes due 2007; $300 million of its 7¼% Convertible Notes due 2010; and $335 million of its unsecured 8⅝% Senior Notes due 2014.

Due to the holding company structure, SPR's right as a common shareholder to receive assets of any of its direct or indirect subsidiaries upon a subsidiary's liquidation or reorganization is junior to the claims against the assets of such subsidiary by its creditors and preferred stockholders. Therefore, SPR's debt obligations are effectively subordinated to all existing and future claims of the creditors of NPC and SPPC and its other subsidiaries, including trade creditors, debt holders, secured creditors, taxing authorities, guarantee holders, NPC's preferred trust security holders, and SPPC's preferred stockholders.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

As of December 31, 2004, SPR, NPC, SPPC, and their subsidiaries had approximately $4.1 billion of debt and other obligations outstanding, consisting of approximately $2.3 billion of debt at NPC, approximately $1 billion of debt at SPPC, and approximately $0.8 billion of debt at the holding company and other subsidiaries. Additionally, SPPC had $50 million of outstanding preferred stock. Although the Utilities are parties to agreements that limit the amount of additional indebtedness they may incur, the Utilities retain the ability to incur substantial additional indebtedness and other liabilities.

Credit Ratings

On March 29 and April 1, 2002, S&P and Moody's lowered the unsecured debt ratings of SPR, NPC, and SPPC to below investment grade in response to the decision of the PUCN with respect to NPC's rate cases. On April 23 and 24, 2002, the unsecured debt ratings of SPR and the Utilities were further downgraded by both rating agencies, and the Utilities' secured debt ratings were downgraded to below investment grade. The downgrades affected SPR's, NPC's, and SPPC's liquidity primarily in two principal areas: (1) their respective financing arrangements, and (2) NPC's and SPPC's contracts for fuel, for purchase and sale of electricity, and for transportation of natural gas.

As a result of the ratings downgrades, SPR's ability to access the capital markets to raise funds remains limited. See Liquidity and Capital Resources—NPC and SPPC, for more information.

Energy Supplier Issues—Contracts

With respect to NPC's and SPPC's contracts for purchased power, NPC and SPPC purchase and sell electricity with counterparties under the Western Systems Power Pool (WSPP) agreement, an industry standard contract that NPC and SPPC are required to use as members of the WSPP. The WSPP contract is posted on the WSPP website.

These contracts provide that a material adverse change may give rise to request adequate financial assurance, which, if not provided within three business days, could cause a default. A default must be declared within 30 days of the event, giving rise to the default becoming known. A default will result in a termination payment equal to the present value of the net gains and losses for the entire remaining term of all contracts between the parties aggregated to a single liquidated amount due within three business days following the date the notice of termination is received. The mark-to-market value, which is substantially based on quoted market prices, can be used to roughly approximate the termination payment and benefit at any point in time. The net mark-to-market value as of December 31, 2004 for all suppliers continuing to provide power under a WSPP agreement would approximate a $164 million payment by NPC and an approximate $10 million payment by SPPC.

Energy Supplier Issues—Contract Terminations

In early May of 2002, Enron Power Marketing Inc. (Enron), Morgan Stanley Capital Group Inc. (MSCG), Reliant Energy Services, Inc., and several smaller suppliers terminated their power deliveries to NPC and SPPC. These terminating suppliers asserted their contractual right under the WSPP agreement to terminate deliveries based upon the Utilities' alleged failure to provide adequate assurance of their performance under the WSPP agreement to any of their suppliers. See Note 14, Commitments and Contingencies of the Notes to Financial Statements for further discussion.

NPC and SPPC have established accrued liabilities, included in their Consolidated Balance Sheets as "Contract termination liabilities," of $246 million and $94 million, respectively, for terminated power supply contracts and associated interest. Correspondingly, pursuant to the deferred energy accounting provisions of AB 369, included in NPC and SPPC deferred energy balances as of December 31, 2004, is approximately $240 million and $84 million of charges associated with the terminated power supply contracts, deferred for recovery in rates in future periods.

If NPC and SPPC are required to pay part or all of the amounts accrued for, the Utilities will pursue recovery of the amounts through future deferred energy filings.

Gas Supplier Issues

With respect to the purchase and sale of natural gas, NPC and SPPC use several types of standard industry contracts. The natural gas contract terms and conditions are more varied than the electric contracts. Consequently, some of the contracts contain language similar to that found in the WSPP agreement and other agreements have unique provisions dealing with material adverse changes. Because of creditworthiness concerns, most contracts and confirmations for natural gas purchases have been modified or separate agreements have been made to either shorten the normal payment due date or require payment in advance of delivery. At the present time, most natural gas purchase transactions require payment in advance of delivery.

Gas transmission service is secured under FERC Tariffs or custom agreements. These service contracts and Tariffs require the user establish and maintain creditworthiness to obtain service or otherwise post cash or a letter of credit to be able to receive service. Service contracts are subject to FERC approved tariffs, which, under certain circumstances, require the Utilities to provide collateral to continue receiving service. To date, a letter of credit has been provided to one of NPC's gas transporters.

Construction Expenditures and Financing (SPR Consolidated)

The table below provides SPR's consolidated cash construction expenditures and internally generated cash for the years ended December 31, 2002 through 2004 (dollars in thousands):

	2004	2003	2002
Cash construction expenditures	**$557,221**	$333,498	$347,997
Net cash flow from operating activities	**$332,041**	$260,564	$454,462
Less common & preferred cash dividends	**3,821**	3,524	24,485
Internally generated cash	**$328,220**	$257,040	$429,977
Internally generated cash as a percentage of cash construction expenditures	**59%**	77%	124%

SPR's consolidated cash construction expenditures for 2005 through 2009 are estimated to be $3.4 billion. Construction expenditures for 2005 are projected to be $806.5 million and are expected to be financed by the Utilities revolving credit facilities and internally generated funds which include recovery of the Utilities deferred energy balances.

Each Utility's 2005–2009 capital forecast includes a coal fired generating station during the forecast period. If these projects are approved by the PUCN, each Utility's steadily improving financial condition, as evidenced by the bond sales in 2004, should allow it to successfully raise funds in the capital markets. For additional information regarding financing, see Liquidity and Capital Resources.

Contractual Obligations (SPR Consolidated)

The table below provides SPR's contractual obligations on a consolidated basis (except as otherwise indicated), not including estimated construction expenditures described above, or Pension funding requirements as discussed in Note 12, Retirement Plan and Postretirement Benefits of the Notes to Financial Statements, as of December 31, 2004, that SPR expects to satisfy through a combination of internally generated cash and, as necessary, through the issuance of short-term and long-term debt (dollars in thousands):

Payment Due by Period

	2005	2006	2007	2008	2009	Thereafter	Total
NPC/SPPC long-term debt maturities	$ 8,491	$ 58,909	$ 8,349	$329,466	$273,110	$2,610,755	$ 3,289,080
NPC/SPPC long-term debt Interest Payments	214,827	214,869	211,453	198,652	185,798	1,673,987	2,699,586
SPR long-term debt maturities	—	—	240,218	—	—	635,000	875,218
SPR long-term debt interest payments	69,693	69,693	69,693	69,693	50,644	132,470	461,886
Purchased power	251,227	256,459	261,463	259,732	225,929	2,790,045	4,044,855
Coal and natural gas	258,870	130,686	102,308	85,032	76,081	555,961	1,208,938
Operating leases	10,709	9,175	7,004	6,798	6,279	43,785	83,748
Total contractual cash obligations	$813,816	$739,791	$900,488	$949,373	$817,841	$8,442,003	$12,663,311

Capital Structure (SPR Consolidated)

SPR's actual capital structure on a consolidated basis was as follows at December 31 (dollars in thousands):

	2004		2003	
Short-term debt[(1)(2)]	**$ 8,491**	0.2%	$ 243,970	4.6%
Long-term debt	**4,081,281**	72.4%	3,579,674	67.4%
Preferred stock	**50,000**	0.9%	50,000	1.0%
Common equity	**1,498,616**	26.5%	1,435,394	27.0%
TOTAL	**$5,638,388**	100%	$5,309,038	100%

(1) *Includes current maturities of long-term debt and capital lease obligations.*

(2) *The December 31, 2003, balance does not include a note payable of $19,666 which is reported as liabilities of discontinued operations. See Note 18, Discontinued Operations and Disposal and Impairment of Long-Lived Asset of the Notes to Financial Statements for further discussion.*

NEVADA POWER COMPANY

RESULTS OF OPERATIONS

NPC recognized net income of $104.3 million in 2004 compared to net income of $19.3 million in 2003 and a net loss of $235 million in 2002. NPC's operating results for 2004 improved over 2003 primarily by the reversal in 2004 of interest charges of approximately $28 million originally recognized in 2003, based on the U.S. District Court decision in our appeal of the Enron Judgment, as discussed in Note 14, Commitments and Contingencies of the Notes to Financial Statements. NPC's operating results for 2004 compared to 2003 were further improved by the absence of the disallowed energy costs in 2003 detailed below. NPC's operating results for 2003 were negatively affected by the write-off of $46 million of disallowed deferred energy costs in May 2003, and the recognition of $28 million of interest costs as a result of the September 26, 2003 judgment entered by the Enron Bankruptcy Court.

NPC's operating results for 2002 reflect the write-off of approximately $465 million (before taxes) of deferred energy costs and related carrying charges as a result of the PUCN's March 29, 2002, decision in NPC's deferred energy rate case to disallow $434 million of deferred purchased fuel and power costs. The PUCN's decision is being challenged by NPC in a lawsuit filed in Nevada state court.

In 2004, NPC paid and declared common stock dividends of $45 million to its parent, SPR. NPC did not pay or declare a common stock dividend to its parent SPR in 2003.

Gross Margin

Gross margin is presented by NPC in order to provide information by segment that management believes aids the reader in determining how profitable the electric business is at the most fundamental level. Gross margin provides a measure of income available to support the other operating expenses of the business and is utilized by management in its analysis of its business.

The components of gross margin for the years ended December 31 (dollars in thousands):

	2004	2003	2002
Operating Revenues:			
Electric	**$1,784,092**	$1,756,146	$1,901,034
Energy Costs:			
Purchased power	**764,347**	781,014	1,241,783
Fuel for power generation	**235,404**	282,968	309,293
Deferred energy costs—disallowed	**1,586**	45,964	434,123
Deferral of energy costs—electric—net	**135,973**	95,911	(179,182)
	1,137,310	1,205,857	1,806,017
Gross margin	**$ 646,782**	$ 550,289	$ 95,017

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

The causes for significant changes in specific lines comprising the results of operations for NPC for the respective years ended are provided below (dollars in thousands, except for amounts per unit).

Electric Operating Revenue

	2004		2003		2002
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
ELECTRIC OPERATING REVENUES					
Residential	**$ 762,907**	**11.5%**	$ 684,331	1.3%	$ 675,837
Commercial	**372,271**	**7.5%**	346,223	0.3%	345,342
Industrial	**529,916**	**3.2%**	513,521	-1.3%	520,116
Retail revenues	**1,665,094**	**7.8%**	1,544,075	0.2%	1,541,295
Other(1)	**118,998**	**-43.9%**	212,071	-41.0%	359,739
TOTAL REVENUES	**$1,784,092**	**1.6%**	$1,756,146	-7.6%	$1,901,034
Retail sales in thousands of megawatt-hours (MWh)	**18,607**	**3.6%**	17,959	4.4%	17,197
Average retail revenue per MWh	**$ 89.49**	**4.1%**	$ 85.98	-4.1%	$ 89.63

(1) Primarily wholesale, as discussed below.

NPC's retail revenues were higher in 2004 primarily due to increases in the number of residential, commercial and industrial customers (5.2%, 5.5%, and 4.5%, respectively) and increases in energy related rates that became effective April 1, 2004, which was the result of NPC's General & Deferred Energy Rate cases (refer to Regulatory Proceedings, later). Cooler summer weather along with warmer winter weather had a minimal impact on overall retail revenues. Based on NPC's projected customer forecast, NPC expects retail electric customers in the Clark County area to continue to grow in the upcoming year. Offsetting these increases in revenues was a decrease in energy related rates that was effective May 19, 2003, which was the result of NPC's Deferred Energy Case (refer to Regulatory Proceedings, later).

NPC's retail revenues were slightly higher in 2003 compared to 2002 primarily due to the hotter than normal summer temperatures and the increase in the number of residential, commercial, and industrial customers (4.9%, 4.9%, and 6.0%, respectively). Offsetting these increases in revenues was a 6.3% decrease in energy related rates that was effective May 19, 2003, which was the result of NPC's Deferred Energy Case (refer to Regulatory Proceedings, later). Also 2003 decreased compared to 2002 due to a one-time rate increase in June 2002 of $.01 per kilowatt-hour, which allowed NPC to accelerate the recovery of its deferred energy balance.

The decrease in Electric Operating Revenues—Other was primarily due to a 63% decrease in the sales volumes of wholesale electric power to other utilities at significantly lower prices per MWh and a refund of $5.9 million owed to transmission customers as a result of FERC's approval of a tariff agreement on July 8, 2004 (refer to Regulatory Proceedings (Utilities), later).

Purchased Power

	2004		2003		2002
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
PURCHASED POWER	**$764,347**	**-2.1%**	$781,014	-37.1%	$1,241,783
Purchased power in thousands of MWhs	**12,319**	**-0.9%**	12,435	-3.7%	12,908
Average cost per MWh of purchased power(1)	**$ 62.41**	**1.5%**	$ 61.51	-21.6%	$ 78.46

(1) Excludes contract termination costs (credits), of $(4.6) million, $16.1 million, and $228.5 million for the years ending 2004, 2003, and 2002, respectively.

NPC's purchased power costs were lower in 2004 compared to 2003 primarily due to lower volumes purchased. Although NPC satisfied more of its native load requirements through purchased power rather than generation, this volume increase was offset by a significant volume decrease in wholesale sales to other utilities and energy marketers, as well as those associated with risk management activities. Additionally, offsetting the decrease was a $4.6 million credit for terminated contracts recorded in 2004 compared to a $16.1 million charge in 2003. See Liquidity and Capital Resources, later, for a discussion of these terminated power contracts. Per unit costs of power increased primarily due to higher Intermediate-Term and Long-Term Firm energy prices.

NPC's purchased power costs were significantly lower in 2003 compared to 2002 due to decreases in prices and volumes. Per unit costs of power decreased primarily due to lower Short-Term Firm energy prices. These price decreases were the result of a less volatile energy market. A $228.5 million charge for terminated contracts recorded in 2002 further contributed to the overall decrease in the total cost of purchased power. Volumes purchased decreased as a result of a reduction in hedging activities due to a change in risk management activities and energy supply strategies described later in Energy Supply. Purchases associated with risk management activities which are included in Short-Term Firm energy, decreased significantly in both volume and price in 2003. Wholesale sales associated with risk management activities decreased in volume by approximately 61%.

Fuel for Power Generation

	2004		2003		2002
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
FUEL FOR POWER GENERATION	**$235,404**	**-16.8%**	$282,968	-8.5%	$309,293
Thousands of MWhs generated	**8,470**	**-8.2%**	9,228	-9.1%	10,147
Average fuel cost per MWh of generated power	**$ 27.79**	**-9.4%**	$ 30.66	-0.6%	$ 30.48

Fuel for power generation costs decreased in 2004 as compared to 2003 due to lower volume and costs to generate electricity. The decrease in volume of generation was primarily due to NPC satisfying more of its native load requirements through purchased power rather than generation. The decrease in average unit fuel cost per megawatt-hour was primarily due to lower coal costs in 2004 compared to 2003.

NPC's 2003 fuel expense decreased compared to 2002 primarily due to a decrease in overall megawatt-hours generated which was primarily due to NPC satisfying more of its native load with purchased power rather than generation.

Deferral of Energy Costs—Net

	2004		2003		2002
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
Deferred energy costs disallowed	**$ 1,586**	**-96.5%**	$ 45,964	-89.4%	$ 434,123
Deferral of energy costs—net	**135,973**	**41.8%**	95,911	N/A	(179,182)
	$137,559		$141,875		$ 254,941

Deferred energy costs disallowed for 2004 reflects the first quarter write-off of $1.6 million of electric deferred energy costs incurred in the twelve months ended September 30, 2003, that were disallowed by the PUCN in their March 24, 2004 decision on NPC's deferred energy rate case. Deferred energy costs disallowed for 2003 reflects the second quarter write-off of $46 million of electric deferred energy costs incurred in the twelve months ended September 30, 2002, that were disallowed by the PUCN in its May 13, 2003 decision on NPC's deferred energy rate case. Deferred energy costs disallowed for 2002 reflects the second quarter write-off of $434 million of electric deferred energy costs incurred in the seven months ended September 30, 2001 that were disallowed by the PUCN in its March 29, 2002 decision on NPC's deferred energy rate case.

Deferred energy costs—net includes the amortization of approved deferred energy costs included in current rates and the under or over-collection of current period energy costs. An under-collection exists when actual energy costs exceed energy revenues currently being recovered in rates. To the extent that actual costs exceed the amounts recoverable in current rates, the difference is recognized as a reduction in recorded costs. Conversely, an over-collection exists when actual energy costs are less than energy revenues currently being recovered in rates resulting in the difference being recognized as an increase in recorded costs. Reference Note 1, Summary of Significant Accounting Policies, Deferral of Energy Costs of Notes to Financial Statements for further detail of deferred energy balances. Amounts for 2004, 2003, and 2002 include amortization of deferred energy costs of $228.8 million, $204.6 million, and $146.6 million, respectively; and under-collections of amounts recoverable in rates of $92.7 million, $108.7 million, and $325.8 million, respectively.

Allowance For Funds Used During Construction (AFUDC)

	2004		2003		2002
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
Allowance for other funds used during construction	**$4,230**	**48.7%**	$2,845	N/A	$ (153)
Allowance for borrowed funds used during construction	**5,738**	**112.5%**	2,700	-20.9%	3,412
	$9,968	**79.8%**	$5,545	70.1%	$3,259

AFUDC for NPC was higher in 2004 compared to 2003 as a result of an increase in the AFUDC rates and an increase in the Construction Work in Progress (CWIP) balance on which AFUDC is calculated. The increase in CWIP was driven by the addition of Lenzie, as well as regular growth. AFUDC for NPC is higher in 2003 compared to 2002 as a result of an increase in the AFUDC rates; however, that was offset in part by a decrease in the CWIP balance on which AFUDC is calculated.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

Other (Income) and Expenses

	2004		2003		2002
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
Other operating expense	**$183,736**	**-6.0%**	$195,483	16.5%	$ 167,768
Maintenance expense	**$ 57,030**	**18.3%**	$ 48,226	17.1%	$ 41,200
Depreciation and amortization	**$118,841**	**8.4%**	$109,655	11.7%	$ 98,198
Income tax expense/(benefit)	**$ 45,135**	**N/A**	$ (12,734)	-90.5%	$(133,411)
Interest charges on long-term debt	**$152,764**	**7.5%**	$142,143	24.1%	$ 114,527
Interest on terminated contracts	**$ (24,171)**	**N/A**	$ 33,879	N/A	$ 4,101
Interest charges—other	**$ 14,533**	**-15.3%**	$ 17,150	-0.8%	$ 17,294
Interest accrued on deferred energy	**$ (20,199)**	**-11.8%**	$ (22,891)	84.4%	$ (12,414)
Disallowed merger costs	**$ 3,961**	**N/A**	$ —	N/A	$ —
Other income	**$ (22,844)**	**24.5%**	$ (18,344)	N/A	$ (742)
Other expense	**$ 6,665**	**12.1%**	$ 5,944	-40.2%	$ 9,933
Income taxes—other income and expense	**$ 11,437**	**-5.6%**	$ 12,120	N/A	$ 1,627

The decrease in Other operating expense during 2004 compared to 2003 reflects the absence in 2004 of the provision for uncollected revenues on transmission service agreements (TSA). The TSA were challenged at FERC by three parties, who had subscribed for service on transmission facilities built to accommodate new generating stations under construction or to be constructed by these parties. Due to delays in constructing their generating facilities, the parties requested delays in the service commencement of their transmission service contracts, claiming that the Open Access Transmission Tariff excused them from paying their full payment obligations under the transmission contracts or otherwise postponed their obligation to pay. Other factors include fewer write-offs of uncollectible retail customer accounts. These decreases were partially offset by bank charges associated with NPC's revolving credit facility, advisor, and legal fees.

The increase in Other operating expense for 2003 compared to the prior year primarily resulted from the increase in the provision for uncollected revenues on TSA as discussed above. The increase is also attributable to write-offs of uncollectible retail customer accounts, higher insurance premiums, higher operating cost at Reid Gardner due to outages, and the recognition of short-term incentive compensation plan costs in 2003. NPC did not recognize incentive plan costs during 2002.

NPC's maintenance expense fluctuates from period to period primarily as a result of the scheduling, magnitude, and number of generation unit overhauls performed. The increase in 2004 was a result of maintenance performed at the Clark and Reid Gardner generating facilities.

Maintenance expense during 2003 increased compared to the prior year due to maintenance performed at the Clark, Mohave, and Navajo generating facilities.

An increase in depreciation and amortization expense between 2004 and 2003 was the result of increases to plant-in-service. Large projects placed in service in 2004 include the Crystal 500KV Sub Expansion, the McCullough Upgrade, and the addition of several substations to accommodate growth in the region. The increase in depreciation and amortization expense in 2003 compared to 2002 was the result of increases to plant-in-service.

Income tax expense/(benefit) changed from income tax benefits recognized for the year ended December 31, 2003 to income tax expense recognized during 2004. The 2004 income tax expense was recognized due to NPC's pre-tax net income in 2004 compared to a pre-tax net loss in 2003. This change in income is due to an increase in operating revenue, offset by a decrease in operating expenses (including purchased power, fuel, and deferred energy costs disallowed), as well as a decrease in interest charges on terminated contracts in 2004. See Note 14, Commitments and Contingencies of the Notes to Financial Statements for discussion on interest on terminated contracts. See Note 11, Income Taxes of the Notes to Financial Statements for additional information regarding the computation of income taxes.

Interest charges on Long-Term Debt increased for the year ended December 31, 2004 compared to 2003 due primarily to increases in long-term debt balances related to new debt issued in November 2004 of $250 million and August 2003 of $350 million. This increase was partially offset by debt redemptions in September 2003 of $210 and $140 million. Interest charges on Long-Term Debt for the year ended December 31, 2003 increased over the same period in 2002 due primarily to the issuance of additional debt in August 2003 of $350 million and in October 2002 of $250 million. This increase was partially offset by redemptions in September 2003 and October 2002, of $350 million and $15 million, respectively. See Note 7, Long-Term Debt of the Notes to Financial Statements for additional information regarding long-term debt.

Interest charges on terminated contracts for the year ended December 31, 2004 reflects the reversal of interest of $28 million resulting from a ruling by the U.S. District Court hearing the utilities appeal against the Bankruptcy Court Judge's ruling in the bankruptcy proceedings of Enron Power Marketing (Enron). In September 2003, NPC recorded $28 million of additional interest costs on terminated contracts as a result of a judgment issued on September 26, 2003 by the Bankruptcy Court Judge overseeing the bankruptcy proceedings of Enron. See Note 14, Commitments and Contingencies of the Notes to Financial Statements for more information regarding the Enron litigation.

Interest charges—other for the year ended December 31, 2004 decreased compared to the same period in 2003 following reduced charges related to NPC's short-term credit facilities. These facilities were replaced during 2004 with long-term facilities; when drawn upon, interest related to the new facilities is chargeable to long-term debt interest.

Interest accrued on deferred energy costs for the year ended December 31, 2004 decreased from the previous year due to lower deferred energy balances. Interest accrued on deferred energy costs for the year ended December 31, 2003 was substantially lower than the amount for the same period in 2002, after adjusting for the first quarter 2002 write-off of $30.9 million in carrying charges due to the disallowance by the PUCN. Also contributing to the 2003 decrease was lower deferred energy balances when compared to deferred energy balances in 2002. See Note 3, Regulatory Actions of the Notes to Financial Statements for further discussion of deferred energy accounting issues.

Disallowed merger costs expense for the year ended December 31, 2004 includes the write-off of costs that resulted from the July 28, 1999 merger between SPR and NPC which were determined to be not recoverable through rates in the March 26, 2004, PUCN decision on NPC's 2003 general rate case. The PUCN decision permitted substantially all of the merger costs that NPC requested recovery of except for a 20% reduction in goodwill and other merger costs that were to be amortized over the next two years. Also included in the write-off are merger costs allocable to non-Nevada jurisdictional sales that NPC has determined will not be recovered in rates. See Regulatory Proceedings (Utilities)—Nevada Power Company 2003 General Rate Case and Note 19, Goodwill and Other Merger Costs of the Notes to Financial Statements for additional information regarding NPC's recovery of merger costs.

NPC's Other income increased for the year ended December 31, 2004 compared to the same period in 2003 due to the recognition of revenue from the disposition of the Flamingo Corridor and other non-utility property beginning during the third quarter, 2003, reduced slightly by lower interest income in 2004 (see Note 18, Discontinued Operations and Disposal and Impairment of Long-Lived Assets, Other Property Disposals of the Notes to Financial Statements for further discussion). NPC's Other income increased for the year ended December 31, 2003 compared to the same period in 2002 due to an increase in gains from the disposition of non-utility property, the recognition of income from the disposition of SO2 allowances in 2003, the income generated as a result of the relocation of electricity lines for Clark County, the recognition of carrying charges related to divestiture costs ordered by the PUCN, and an increase in interest income.

NPC's Other expense was comparable for 2004 to 2003. NPC's Other expense decreased for 2003 compared to 2002 due primarily to the absence in 2003 of charges incurred during 2002 associated with NPC's contribution to a group opposed to the inclusion of an Electric Utility Advisory Question to the November 2002 general election ballot and the write-off of amounts relating to the disposition of SO2 allowances as ordered by the PUCN.

NPC's Income Taxes—Other Income and Expense for the year ended December 31, 2004 was comparable to the year ended December 31, 2003. NPC's Income Taxes—Other Income and Expense increased in 2003 compared to 2002 due to an increase in pre-tax other income largely as a result of a write-off of disallowed interest charges on deferred energy costs in 2002.

ANALYSIS OF CASH FLOWS

NPC had improved operating cash flows in 2004, when compared to 2003, due mainly to rate increases that went into effect in the second quarter of 2004 to recover deferred energy balances and operating costs, and reduced requirements to prepay for energy costs due to the securing of credit lines. These benefits were partially offset by higher interest payments and the payment of $50 million into the Enron escrow account ordered by the court overseeing the Enron bankruptcy proceedings. Net cash used by investing activities increased due to the purchase of the partially constructed Lenzie project from Duke Energy financed entirely by new debt, which represents the increase in cash from financing activities. Cash from financing activities was offset by dividend payments to SPR of $45 million.

NPC's cash flows were less during 2003, when compared to 2002, due to a decrease in cash flows from financing activities that was partially offset by a small increase in cash flows from operating activities and a reduction in cash used in investing activities. NPC utilized internally generated cash to fund construction activity in 2003 due to its weakened financial condition, which resulted in a decrease in cash flows from financing activities when compared to 2002. Cash flows from operating activities increased as a result of the collection of previously deferred energy costs due to PUCN decisions in NPC's 2001 and 2002 deferred energy rate cases that resulted in rate increases beginning April 1, 2002, and May 19, 2003, respectively. Also contributing to improved operating cash flows in 2003 was lower purchased power costs, partially offset by the requirement to prepay or accelerate the payment for fuel and power purchases during 2003 and the receipt of an income tax refund in 2002. Reduced construction expenditure resulted in a reduction in cash used by investing activities.

LIQUIDITY AND CAPITAL RESOURCES

NPC had cash and cash equivalents of approximately $243 million at December 31, 2004.

NPC anticipates capital requirements for construction costs in 2005 will be approximately $629.8 million. Total construction costs include the recently announced Lenzie project. NPC expects to finance its capital requirements with a combination of internally generated funds, including the recovery of deferred energy, and the use of existing credit facilities.

Chuck Lenzie Generating Station Financing Plan

On June 23, 2004, NPC announced that it reached an agreement to acquire from Duke Energy the partially constructed nominally rated 1,200 MW natural gas-fired combined-cycle power plant located north of Las Vegas, the Lenzie project. Total costs to acquire and complete construction of the facility are estimated at $558 million, of which $182 million is for the facility in its current state of completion. The transaction was approved by the PUCN on September 17, 2004 and closed on October 13, 2004.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

The financing plan associated with the purchase and construction, and as outlined in the Lenzie Financing Application filed with the PUCN, consists of the following steps:

- NPC financed the acquisition with a $250 million revolving credit facility that was put in place on October 8, 2004 and increased to $350 million on October 22, 2004. NPC borrowed $150 million under this revolving credit facility to fund a portion of the $182 million acquisition price. This facility will also be used to fund some of the initial construction expenditures.
- On November 16, 2004, NPC issued its 5⅞% General and Refunding Mortgage Notes Series L, due January 15, 2015 in the amount of $250 million. A portion of the proceeds from this financing were used to pay down the outstanding balance of the revolving credit facility, and some or all of the balance will also be used to fund a portion of the construction of the Lenzie facility.
- The $350 million revolving credit facility, in conjunction with available internally generated funds, will be used to complete the construction of the Lenzie facility as well as the construction of the Harry Allen combustion turbine.

Over the plan period, NPC's internally generated cash contributions will represent an equity investment in the facility, with the intention to finance the plant approximately 50 percent with equity and 50 percent with long-term debt. See Nevada Power Company Subsequent Material Amendment to its 2003 Resource Plan under Regulatory Proceedings (Utilities).

Mortgage Indentures

NPC's Indenture of Mortgage, dated as of October 1, 1953, between NPC and Deutsche Bank Trust Company Americas (the "First Mortgage Indenture"), creates a first priority lien on substantially all of NPC's properties. As of December 31, 2004, $372.5 million of NPC's first mortgage bonds were outstanding. In connection with the issuance of its Series E, Series G, and Series I Notes, NPC agreed that it would not issue any more first mortgage bonds.

NPC's First Mortgage Indenture limits the cumulative amount of dividends and other distributions that NPC may pay on its capital stock. In February 2004, NPC amended this restriction in its First Mortgage Indenture to:

(1) change the starting point for the measurement of cumulative net earnings available for the payment of dividends on NPC's capital stock from March 31, 1953 to July 28, 1999 (the date of NPC's merger with SPR), and

(2) permit NPC to include in its calculation of proceeds available for dividends and other distributions the capital contributions made to NPC by SPR.

NPC does not anticipate that the First Mortgage Indenture dividend restriction, as amended, will materially limit the amount of dividends that it may pay to SPR in the foreseeable future.

NPC's General and Refunding Mortgage Indenture creates a lien on substantially all of NPC's properties in Nevada that is junior to the lien of the first mortgage indenture. As of December 31, 2004, $1.3 billion of NPC's General and Refunding Mortgage securities were outstanding. Additional securities may be issued under the General and Refunding Mortgage Indenture on the basis of:

(1) 70% of net utility property additions,

(2) the principal amount of retired General and Refunding Mortgage Bonds, and/or

(3) the principal amount of first mortgage bonds retired after October 19, 2001.

On the basis of (1), (2), and (3) above and on plant accounting records as of December 31, 2004 (which do not include additions to plant associated with the acquisition of the Lenzie Generating Station), as of January 31, 2005, NPC had the capacity to issue approximately $272 million of additional General and Refunding Mortgage securities.

Although NPC has substantial capacity to issue additional General and Refunding Mortgage securities on the basis of property additions and retired securities, the financial covenants contained in the Series E, Series G, Series I, and Series L Notes, the Series H Bond and the Revolving Credit Facility limit the amount of additional indebtedness that NPC may issue and the reasons for which such indebtedness may be issued.

NPC also has the ability to release property from the liens of the two mortgage indentures on the basis of net property additions, cash and/or retired bonds. To the extent NPC releases property from the lien of its General and Refunding Mortgage Indenture, it will reduce the amount of securities issuable under that indenture.

Financing Transactions

General and Refunding Mortgage Notes, Series L

On November 16, 2004, NPC issued and sold $250 million of its 5⅞% General and Refunding Mortgage Notes, Series L, due January 15, 2015. The Series L Notes were issued with registration rights. The proceeds of the issuance were used to repay $150 million outstanding under NPC's $350 million revolving credit facility expiring October 8, 2007. Remaining proceeds will be used to pay costs in connection with the acquisition and construction of Lenzie and for general corporate purposes.

The Series L Notes, similar to NPC's Series E, Series G and Series I Notes, and Series H Bond, limit the amount of payments in respect of common stock dividends that NPC may pay to SPR. This limitation is discussed in Note 9, Dividend Restrictions of the Notes to Financial Statements.

The terms of the Series L Notes, as with the Series E Notes, Series G Notes, Series I Notes, and Series H Bond, also restrict NPC from incurring any additional indebtedness unless:

(1) at the time the debt is incurred, the ratio of consolidated cash flow to fixed charges for NPC's most recently ended four quarter period on a pro forma basis is at least 2 to 1, or

(2) the debt incurred is specifically permitted under the terms of the applicable Notes or Bond, which permits the incurrence of certain credit facility or letter of credit indebtedness, obligations incurred to finance property construction or improvement, indebtedness incurred to refinance existing indebtedness, certain intercompany indebtedness, hedging obligations, indebtedness incurred to support bid, performance or surety bonds, and certain letters of credit issued to support NPC's obligations with respect to energy suppliers, or

(3) in the case of the Series G Notes, Series I Notes and Series L Notes, and the Series H Bond indebtedness incurred to finance capital expenditures pursuant to NPC's 2003 Integrated Resource Plan.

If NPC's Series E Notes, Series G Notes, Series I Notes, Series L Notes, or Series H Bond are upgraded to investment grade by both Moody's Investor Service, Inc. (Moody's) and Standard & Poor's Rating Group, Inc. (S&P), these restrictions will be suspended and will no longer be in effect so long as the applicable series of Notes or the Bond remains investment grade.

Among other things, the Series E Notes, Series G Notes, Series I Notes, Series L Notes, and Series H Bond also contain restrictions on liens (other than permitted liens, which include liens to secure certain permitted debt) and certain sale and leaseback transactions. In the event of a change of control of NPC, the holders of these securities are entitled to require that NPC repurchase their securities for a cash payment equal to 101% of the aggregate principal amount plus accrued and unpaid interest.

Revolving Credit Facility

On October 8, 2004, NPC entered into a $250 million Credit Agreement with Union Bank of California, N.A., as Administrative Agent, to finance the purchase price of Lenzie and to pay fees, costs, and expenses incurred by NPC in connection with the purchase and construction of Lenzie and for general corporate purposes. On October 22, 2004, NPC amended and restated the Credit Agreement to increase the total size of the revolving credit facility to $350 million, concurrently with its termination of its $100 million Credit Facility, which was established on May 4, 2004.

The new revolving credit facility, which is secured by NPC's $350 million General and Refunding Mortgage Bond, Series K, will expire October 8, 2007. The rate for outstanding loans and/or letters of credit under revolving credit facility will be at either an alternate base rate or a Eurodollar rate plus a margin that varies based upon NPC's credit rating by S&P and Moody's. Currently, NPC's alternate base rate margin is 1% and its Eurodollar margin is 2%.

On October 8, 2004, NPC borrowed $150 million under the revolving credit facility to pay part of the $182 million purchase price for the Facility. The remainder of the purchase price was funded with available cash. This $150 million outstanding balance was paid off concurrently with receiving the proceeds of the General and Refunding Mortgage Notes, Series L, issued on November 16, 2004.

The NPC Credit Agreement contains two financial maintenance covenants. The first requires that NPC maintain a ratio of consolidated indebtedness to consolidated capital, determined as of the last day of each fiscal quarter, not to exceed 0.68 to 1. The second requires that NPC maintain a ratio of consolidated cash flow to consolidated interest expense, determined as of the last day of each fiscal quarter for the period of four consecutive fiscal quarters, not to be less than 2.0 to 1.

The NPC Credit Agreement, similar to NPC's Series E Notes, Series G Notes, Series I Notes, Series L Notes, and Series H Bond limits the amount of payments in respect of common stock dividends that NPC may pay to SPR. This limitation is discussed in Note 9, Dividend Restrictions of the Notes to Financial Statements.

The Credit Agreement also contains a restriction on NPC's ability to incur additional indebtedness which is similar to the restriction discussed above for NPC's Series L Notes.

Among other things, the NPC Credit Agreement also contains restrictions on liens (other than permitted liens, which include liens to secure certain permitted debt) and certain sale and leaseback transactions. There are also limitations on certain fundamental structural changes to NPC and limitations on the disposition of property.

The NPC Credit Agreement provides for certain events of default including any of the following events: NPC fails to make payments of principal or interest under the Credit Agreement, NPC fails to comply with certain agreements included in the Credit Agreement, NPC files for bankruptcy, or a change of control occurs. The Credit Agreement also provides for an event of default if a judgment of $15 million or more is entered against NPC and such judgment is not vacated, discharged, stayed, or bonded pending appeal within 60 days. Since, the Credit Agreement also prohibits the creation or existence of any liens on NPC's properties except for liens specifically permitted under the Credit Agreement, if a judgment lien is filed against NPC, the filing of the lien will trigger an event of default under the Credit Agreement. The Credit Agreement also provides for an event of default if NPC defaults in the payment of principal, interest, or premium beyond the applicable grace period under any mortgage, indenture, or other security instrument, relating to debt in excess of $15 million.

Upon an event of default, the Administrative Agent under the NPC Credit Agreement may, upon request of more than 50% of the lenders under the Credit Agreement, declare all amounts due under the Credit Agreement immediately due and payable. Since NPC's obligations under the Credit Agreement are secured by its General and Refunding Mortgage Bond, if NPC fails to repay all amounts due upon an acceleration of the Credit Agreement within three business days, such failure will be deemed a default in the payment of principal and will trigger an event of default under the NPC General and Refunding Mortgage Indenture that would be applicable to all securities issued under the NPC General and Refunding Mortgage Indenture.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

$100 Million Revolving Credit Facility

On May 4, 2004, NPC established a $100 million Revolving Credit Facility with a maturity date of May 4, 2009. Borrowings under this facility were secured by NPC's General and Refunding Mortgage Bond, Series J, due 2009. On June 30, 2004, NPC drew upon this new Revolving Credit Facility for $10 million to meet necessary liquidity needs for ongoing operations. NPC repaid its outstanding borrowings on August 4, 2004.

Concurrent with the amendment and restatement of the new $350 million Revolving Credit Facility, discussed above, this facility was terminated on October 22, 2004. There were no amounts outstanding under this facility at the time of termination.

General and Refunding Mortgage Notes, Series I

On April 7, 2004, NPC issued and sold $130 million of its 6½% General and Refunding Mortgage Notes, Series I, due April 15, 2012. The Series I Notes, which were issued with registration rights, were exchanged for registered notes in October 2004. The proceeds of the issuance were used to pay off $130 million aggregate principal amount of NPC's 6.20% Series B, Senior Notes due April 15, 2004. The Series I Notes contain terms and provisions substantially similar to those in the Series L Notes, discussed above.

Accounts Receivable Facility

On October 29, 2002, NPC established an accounts receivable purchase facility of up to $125 million. On May 4, 2004, the company delivered a notice of termination of its accounts receivable facility in connection with the establishment of its new revolving credit facility. The termination was effective on May 19, 2004.

Financial Covenants

NPC's $350 million Revolving Credit Agreement, as amended and restated on October 22, 2004, contains two financial maintenance covenants. The first requires that NPC maintain a ratio of consolidated indebtedness to consolidated capital, determined as of the last day of each fiscal quarter, not to exceed 0.68 to 1. The second requires that NPC maintain a ratio of consolidated cash flow to consolidated interest expense, determined as of the last day of each fiscal quarter for the period of four consecutive fiscal quarters, not to be less than 2.0 to 1.

Cross-Default Provisions

None of the financing agreements of NPC contain a cross-default provision that would result in an event of default by NPC upon an event of default by SPR or SPPC under any of its financing agreements. In addition, certain financing agreements of NPC provide for an event of default if there is a failure under other financing agreements of NPC to meet payment terms or to observe other covenants that would result in an acceleration of payments due. Most of these default provisions (other than ones relating to a failure to pay other indebtedness) provide for a cure period of 30-60 days from the occurrence of a specified event during which time NPC may rectify or correct the situation before it becomes an event of default. The primary cross-default provisions in NPC's various financing agreements are summarized below:

- NPC's General and Refunding Mortgage Indenture, under which NPC has $1.3 billion of securities outstanding (excluding NPC's Series H Bond, which is held in escrow in connection with the Enron litigation) as of December 31, 2004, provides for an event of default if a matured event of default under NPC's First Mortgage Indenture occurs;
- The terms of NPC's Series E Notes, Series G Notes, Series I Notes, Series L Notes, and Series H Bond provide that a default with respect to the payment of principal, interest, or premium beyond the applicable grace period under any mortgage, indenture or other security instrument by NPC or any of its restricted subsidiaries, relating to debt in excess of $15 million, triggers a right of the holders of the Series E Notes, Series G Notes, Series I Notes, Series L Notes, and Series H Bond to require NPC to redeem their series of Notes or the Bonds at a price equal to 100% of the aggregate principal amount plus accrued and unpaid interest and liquidated damages, if any, upon notice given by at least 25% of the outstanding noteholders for such series of Notes or Bonds; and
- NPC's $350 million Credit Agreement provides for an event of default if NPC defaults in the payment of principal, interest, or premium beyond the applicable grace period under any mortgage, indenture or other security instrument relating to debt in excess of $15 million. Upon an event of default, the Administrative Agent under the NPC Credit Agreement may, upon request of more than 50% of the lenders under the Credit Agreement, declare all amounts due under the Credit Agreement immediately due and payable. Since NPC's obligations under the Credit Agreement are secured by its General and Refunding Mortgage Bond, if NPC fails to repay all amounts due upon an acceleration of the Credit Agreement within three business days, such failure will be deemed a default in the payment of principal and will trigger an event of default under NPC's General and Refunding Mortgage Indenture that would be applicable to all securities issued under NPC's General and Refunding Mortgage Indenture.

Judgment Related Defaults

NPC's First Mortgage Indenture provides for an event of default if a final, unstayed judgment in excess of $25,000 is rendered against NPC and remains undischarged for 60 days. Upon a matured event of default, the trustee may, and upon the written request of the holders of at least 25% of the bonds outstanding under NPC's First Mortgage Indenture, is required to declare the principal of and interest on the approximately $372.5 million of outstanding First Mortgage Bonds immediately due and payable.

The terms of NPC's $250 million Series E, $350 million Series G, $130 million Series I, and $250 million Series L General and Refunding Mortgage Notes, $186 million Series H General and Refunding Mortgage Bond and $350 million Revolving Credit Facility provide for an event of default if a final, unstayed judgment in excess of $15 million is rendered against NPC and remains undischarged for 60 days. Since the Series E, Series G, Series I and Series L Notes, and Series H Bond were issued under NPC's General and Refunding Mortgage Indenture and NPC's revolving credit facility is secured by a General and Refunding Mortgage Bond, a default under any of the Series E, Series G, and Series I Notes, Series H Bond, and Revolving Credit Facility will trigger a default under NPC's General and Refunding Mortgage Indenture.

In addition, a matured event of default under NPC's First Mortgage Indenture will trigger a default under NPC's General and Refunding Mortgage Indenture. Upon a matured event of default under the NPC's General and Refunding Mortgage Indenture, the trustee or the holders of 33% of the General and Refunding Mortgage securities outstanding may declare the principal and accrued interest of the approximately $1.3 billion of outstanding General and Refunding Mortgage securities (excluding NPC's Series H Bond, which is held in escrow) as of December 31, 2004, immediately due and payable.

If a judgment lien is created on NPC's real property located in Nevada, NPC has been advised that the judgment lien would be an interceding lien that would have priority over subsequent advances under NPC's General and Refunding Mortgage Indenture; therefore, NPC would be unable to provide certain required opinions of counsel to issue additional securities under its General and Refunding Mortgage Indenture until the judgment lien is discharged and released. Since NPC is unable to issue additional bonds under its First Mortgage Indenture, its sole means of issuing secured debt is through its General and Refunding Mortgage Indenture.

Pension Plan Matters

SPR has a qualified pension plan that covers substantially all employees of SPR, NPC, and SPPC. The annual net benefit cost for the plan will decrease for 2005 by approximately $5.6 million over the 2004 cost of $28.3 million. As of September 30, 2004, the measurement date, the plan was fully funded. During 2004, NPC contributed a total of $17 million to meet their funding obligations under the plan. At the present time, it is not expected that any additional funding will be required in 2005 to meet the minimum funding levels defined by the Pension Benefit Guaranty Corporation.

Limitations on Indebtedness

The terms of NPC's Series E Notes, which mature in 2009, NPC's Series G Notes, which mature in 2013, NPC's Series I Notes, which mature in 2012, NPC's Series L Notes, which mature in 2015, NPC's Series H Bond, and NPC's Revolving Credit Facility restrict NPC from incurring any additional indebtedness unless:

(1) at the time the debt is incurred, the ratio of consolidated cash flow to fixed charges for NPC's most recently ended four quarter period on a pro forma basis is at least 2.0 to 1, or

(2) the debt incurred is specifically permitted, which includes limited amounts of debt with respect to certain credit facility or letter of credit indebtedness, obligations incurred to finance property construction or improvement, indebtedness incurred to refinance existing indebtedness, certain intercompany indebtedness, hedging obligations, indebtedness incurred to support bid, performance or surety bonds, certain letters of credit issued to support NPC's obligations with respect to energy suppliers, and for the Series G Notes, Series I Notes, Series L Notes, the Series H Bond and the revolving credit facility indebtedness to finance capital expenditures incurred pursuant to NPC's 2003 IRP.

If NPC's Series E Notes, Series G Notes, Series I Notes, Series L Notes, or the Series H Bond are upgraded to investment grade by both Moody's and S&P, these restrictions will be suspended and will no longer be in effect so long as the applicable series of securities remains investment grade.

Credit Ratings

On March 29 and April 1, 2002, following the decision by the PUCN in NPC's deferred energy rate case, S&P and Moody's lowered NPC's unsecured debt ratings to below investment grade. On April 23 and 24, 2002, NPC's unsecured debt ratings were further downgraded and its secured debt ratings were downgraded to below investment grade.

In connection with the credit downgrades by S&P and Moody's, NPC lost its A2/P2 commercial paper ratings and can no longer issue commercial paper. NPC does not expect to have direct access to the commercial paper market for the foreseeable future.

Energy Supplier Issues—Contract Terminations

In early May of 2002, Enron Power Marketing Inc. (Enron), Morgan Stanley Capital Group Inc. (MSCG), Reliant Energy Services, Inc., and several smaller suppliers terminated their contracts for power deliveries to NPC. These terminating suppliers asserted their contractual right under the WSPP agreement to terminate deliveries based upon NPC's alleged failure to provide adequate assurance of its performance under the WSPP agreement to any of their suppliers. For further discussion of Contract Terminations, see Note 14, Commitments and Contingencies of the Notes to Financial Statements.

Included in NPC's Consolidated Balance Sheets as "Contract termination liability," are $246 million of estimated liabilities, for terminated power supply contracts and associated interest. Correspondingly, pursuant to the deferred energy accounting provisions of AB 369, included in NPC's deferred energy balance as of December 31, 2004, is approximately $240 million of charges associated with the terminated power supply contracts, deferred for recovery in rates in future periods.

If NPC is required to pay part or all of the amounts accrued for, NPC will pursue recovery of the amounts through future deferred energy filings. To the extent that NPC is not permitted to recover any portion of these costs through a deferred energy filing, the amounts not permitted would be charged as a current operating expense.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

PUCN Order

On March 31, 2004, the PUCN issued an order in connection with its authorization of the issuance of secured long-term debt securities by NPC in an aggregate amount not to exceed $230 million. The PUCN order, for Docket 04-1014, approved NPC's financial application with a restriction on NPC's ability to dividend funds up to SPR. The restriction does not prohibit NPC from paying dividends to SPR for amounts necessary for SPR to meet its future interest payments requirements. The PUCN order expires December 31, 2005.

Construction Expenditures and Financing

The table below provides an overview of NPC's consolidated cash construction expenditures and internally generated cash for the years ended December 31 (dollars in thousands):

	2004	2003	2002
Cash construction expenditures	**$453,745**	$206,913	$252,927
Net cash flow from operating activities	**$342,640**	$267,930	$260,093
Common and preferred cash dividends paid	**44,975**	—	10,000
Internally generated cash	**297,665**	267,930	250,093
Investment by parent company	**—**	—	10,000
Total cash available	**$297,665**	$267,930	$260,093
Internally generated cash as a percentage of cash construction expenditures	**66%**	129%	99%
Total cash generated (used) as a percentage of cash construction expenditures	**66%**	129%	103%

NPC's estimated cash construction expenditures for 2005 through 2009 are $2.4 billion. Construction expenditures for 2005 are projected to be $629.8 million and are expected to be financed by existing revolving credit facilities and internally generated funds which include recovery of deferred energy balances.

NPC's 2005–2009 capital forecast includes a coal fired generating station during the forecast period. If this project is approved by the PUCN, NPC believes that its improved financial condition, as evidenced by the bond sales in 2004, should allow it to successfully raise funds in the capital markets. For additional information regarding financing, see Liquidity and Capital Resources.

Contractual Obligations

The table below provides NPC's consolidated contractual obligations, not including estimated construction expenditures described above, as of December 31, 2004, that NPC expects to satisfy through a combination of internally generated cash and, as necessary, through the issuance of short-term and long-term debt (dollars in thousands):

Payment Due By Period

	2005	2006	2007	2008	2009	Thereafter	Total
Long-term debt maturities	$ 6,091	$ 6,509	$ 5,949	$ 7,066	$272,510	$1,993,505	$2,291,630
Long-term debt interest payments	145,598	145,597	145,595	145,594	145,540	1,265,517	1,993,441
Purchased power	221,625	225,890	230,459	227,033	208,359	2,790,045	3,903,411
Coal and natural gas	106,845	52,672	47,109	36,941	36,866	246,569	527,002
Operating leases	2,068	1,107	37	11	11	453	3,687
Total contractual cash obligations	$482,227	$431,775	$429,149	$416,645	$663,286	$6,296,089	$8,719,171

Capital Structure

NPC's actual consolidated capital structure was as follows at December 31 (dollars in thousands):

	2004		2003	
Short-term debt[1]	**$ 6,091**	**0.2%**	$ 135,570	4.2%
Long-term debt	**2,275,690**	**61.2%**	1,899,709	59.2%
Common equity	**1,436,788**	**38.6%**	1,174,645	36.6%
Total	**$3,718,569**	**100%**	$3,209,924	100%

(1) Includes current maturities of long-term debt and capital lease obligations.

SIERRA PACIFIC POWER COMPANY

RESULTS OF OPERATIONS

SPPC recognized net income of $18.6 million compared to a net loss of $23.3 million in 2003, and compared to a net loss of $14.0 million in 2002. SPPC's operating results for 2004 were improved over 2003 primarily by the reversal in 2004 of interest charges of approximately $12 million originally recognized in 2003 based on the U.S. District Court decision in our appeal of the Enron Judgment, as discussed in Note 14, Commitments and Contingencies of the Notes to Financial Statements. SPPC's operating results for 2004 compared to 2003 were further improved by the absence of the disallowed energy costs in 2003 detailed below. Partially offsetting the improved operating results were costs of approximately $47 million disallowed as a result of the decision by the PUCN to disallow recovery of a portion of the costs associated with the Piñon Pine power plant project. In 2003, SPPC's operating results were negatively affected by a write-off of $45 million of disallowed deferred energy costs in June 2003, and the recognition of $12 million of interest costs as a result of the September 26, 2003, Judgment by the Bankruptcy Court.

SPPC's operating results for 2002 reflect the write-off of approximately $58 million (before taxes) of deferred energy costs and related carrying charges as a result of the PUCN's May 28, 2002 decision in SPPC's deferred energy rate case. The PUCN's decision is being challenged by SPPC in a lawsuit filed in Nevada state court.

SPPC did not pay or declare a common dividend for the year ended December 31, 2004. For the year ended December 31, 2004, SPPC declared and paid $3.9 million in dividends to holders of its preferred stock. During 2003, SPPC paid $3.9 million in dividends to holders of its preferred stock and an $18.5 million dividend on its common stock, all of which is held by its parent, SPR.

Gross Margin

Gross margin is presented by SPPC in order to provide information by segment that management believes aids the reader in determining how profitable the electric and gas businesses are at the most fundamental level. Gross margin provides a measure of income available to support the other operating expenses of the business and is utilized by management in its analysis of its business. The components of gross margin for the years ended December 31 (dollars in thousands):

	2004	2003	2002
Operating Revenues:			
Electric	**$ 881,908**	$ 868,280	$ 931,251
Gas	**153,752**	161,586	149,783
	$1,035,660	$1,029,866	$1,081,034
Energy Costs:			
Purchased power	**$ 304,955**	$ 364,205	$ 545,040
Fuel for power generation	**224,074**	197,569	144,143
Deferred energy costs disallowed(1)	**—**	45,000	56,958
Deferral of energy costs—electric—net	**7,060**	1,982	(54,632)
Gas purchased for resale	**121,526**	111,675	91,961
Deferral of energy costs—gas—net	**(4,136)**	16,155	24,785
	653,479	736,586	808,255
Energy Costs by Segment:			
Electric	**$ 536,089**	$ 608,756	$ 691,509
Gas	**117,390**	127,830	116,746
	$ 653,479	$ 736,586	$ 808,255
Gross Margin by Segment:			
Electric	**$ 345,819**	$ 259,524	$ 239,742
Gas	**36,362**	33,756	33,037
	$ 382,181	$ 293,280	$ 272,779

(1) 2002 deferred energy costs disallowed includes $53,101 and $3,857 of disallowed electric and gas costs, respectively.

The causes for significant changes in specific lines comprising the results of operations for the years ended are provided below (dollars in thousands except for amounts per unit):

Electric Operating Revenues

	2004		2003		2002
	Amount	**Change from Prior Year**	Amount	Change from Prior year	Amount
ELECTRIC OPERATING REVENUES					
Residential	**$249,287**	**8.2%**	$230,299	5.3%	$218,663
Commercial	**294,956**	**6.7%**	276,453	2.9%	268,631
Industrial	**295,882**	**5.7%**	280,047	3.9%	269,610
Retail revenues	**840,125**	**6.8%**	786,799	3.9%	756,904
Other(1)	**41,783**	**-48.7%**	81,481	-53.3%	174,347
TOTAL REVENUES	**$881,908**	**1.6%**	$868,280	-6.8%	$931,251
Retail sales in thousands of megawatt-hours (MWh)	**9,143**	**2.7%**	8,901	2.4%	8,692
Average retail revenue per MWh	**$ 91.89**	**4.0%**	$ 88.39	1.5%	$ 87.08

(1) Primarily wholesale, as discussed below.

SPPC's retail revenues increased in 2004 as compared to 2003 due to increases in Nevada customer rates as a result of SPPC's General Rate Case, effective June 1, 2004, SPPC's Deferred Energy Case, effective July 15, 2004, and as a result of an increase in California customer energy rates effective December 1, 2004 (refer to Regulatory Proceedings, later). Also contributing to this increase in retail revenues was colder winter weather mostly offset by cooler summer temperatures and an overall growth in retail customers of 2.9%.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

SPPC's retail revenues increased in 2003 as compared to 2002 due to a combination of factors. Increased sales resulting from hotter summer temperatures in 2003 resulted in higher revenues from air conditioning use which were partially offset by lower winter sales from heating resulting from warmer winter weather in 2003. Retail revenues also increased as a result of a small net rate increase and an increase in the number of residential, commercial, and industrial customers (2.2%, 1.9%, and 6.7%, respectively). The net rate increase was effective June 1, 2002, and was partially offset by a decrease in energy related rates effective June 1, 2003. The June 2003 rate decrease was the result of SPPC's Deferred Energy Case.

The decrease in Electric Operating Revenues—Other was primarily due to a 63% decrease in the sales volumes of wholesale power to other utilities at significantly lower prices per MWh.

Gas Operating Revenues

	2004		2003		2002
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
GAS OPERATING REVENUES					
Residential	**$ 81,262**	**7.5%**	$ 75,571	-1.1%	$ 76,400
Commercial	**39,019**	**6.8%**	36,531	-1.3%	37,018
Industrial	**12,336**	**-11.4%**	13,930	-31.2%	20,252
Retail revenues	**132,617**	**5.2%**	126,032	-5.7%	133,670
Wholesale	**18,122**	**-45.0%**	32,978	133.5%	14,121
Miscellaneous	**3,013**	**17.0%**	2,576	29.3%	1,992
TOTAL REVENUES	**$153,752**	**-4.8%**	$161,586	7.9%	$149,783
Retail sales in thousands of decatherms	**13,896**	**-6.2%**	13,089	-6.7%	14,030
Average retail revenues per decatherm	**$ 9.54**	**-0.9%**	$ 9.63	1.0%	$ 9.53

SPPC's retail residential and commercial gas revenues increased in 2004 compared to 2003 primarily due to colder fall and winter temperatures, which were partially offset by warmer spring temperatures. Also contributing to the increase was an increase in energy related rates effective November 1, 2004 and increases in the number of residential and commercial customers (4.3% and 2.8%, respectively). Partially offsetting these increases was a decrease in energy related rates effective November 1, 2003. These changes in energy rates were the result of SPPC's Purchased Gas Adjustment filings (refer to Regulatory Proceedings, later). The decrease in industrial retail revenues was attributable to a shift of industrial customers to either SPPC's gas transportation tariff or to the Company's commercial gas tariff. Under SPPC's gas transportation tariff, customers can procure their own gas from a source other than SPPC but continue to compensate SPPC for its gas transportation costs (see miscellaneous revenues below). Gas usage is reviewed once a year and if a customer meets the requirement, they are migrated in October.

SPPC's retail gas revenues were lower in 2003 compared to 2002 primarily due to warmer winter weather in 2003 and a decrease in energy related rates that became effective January 1, 2003. This decrease in the retail rates was the result of SPPC's Purchased Gas Adjustment filing (see Regulatory Proceedings). Partially offsetting these items was an increase in revenues as result of an increase in the number of residential and commercial customers (3.7% and 2.1%, respectively). The significant decrease in industrial retail revenues was attributable to a shift of industrial customers to SPPC's gas transportation tariff.

Wholesale gas revenues decreased significantly in 2004 compared to 2003. U.S. western region gas prices in 2004 have been higher than 2003 prices, which adversely affected resale opportunities in 2004.

The significant increase in wholesale revenues during 2003 compared to 2002 was primarily due to the utilization of idle gas transportation capacity that allowed SPPC to move gas from Canada to California for resale.

Miscellaneous revenues increased both in 2004 and 2003 primarily due to an increase in revenues pertaining to the transportation of gas for industrial customers that shifted to SPPC's transportation tariff.

Purchased Power

	2004		2003		2002
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
PURCHASED POWER	**$304,955**	**-16.3%**	$364,205	-33.2%	$545,040
Purchased power in thousands of MWh	**5,719**	**-13.0%**	6,575	-8.8%	7,206
Average cost per MWh of purchased power(1)	**$ 53.32**	**-3.2%**	$ 55.07	-13.4%	$ 63.59

(1) Average Cost Per MWh calculation excludes contract termination costs of $2.1 million and $86.8 for the years ending 2003 and 2002, respectively.

Purchased power costs were lower in 2004 compared to 2003 due to overall price and volume decreases. Price decreases were primarily due to a decrease in the average cost for Short-Term Firm energy. Volume decreases were a result of SPPC satisfying more of its native load requirements through its own generation rather than purchased power (see Fuel For Power Generation, which follows) as well as decreases in wholesale electric sales as discussed in Electric Operating Revenue—Other. See Liquidity and Capital Resources, later, for a discussion of these terminated power contracts.

Purchased power costs decreased in 2003 compared to 2002 due to overall price and volume decreases. Price decreases were the result of a less volatile energy market. In addition, an $86.8 million provision for terminated contracts was recorded in the second quarter of 2002. Purchased power costs also reflect a decrease in wholesale sales activity. Purchases associated with risk management activities, which include transactions entered into for hedging purposes and to optimize purchased power costs, are included in the purchased power amounts. See Energy Supply, later, for a discussion of the Utilities' purchased power procurement strategies.

Fuel For Power Generation

	2004		2003		2002
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
FUEL FOR POWER GENERATION	**$224,074**	**13.4%**	$197,569	37.1%	$144,143
Thousands of MWh generated	**4,605**	**9.9%**	4,189	-10.9%	4,699
Average fuel cost per MWh of generated power	**$ 48.66**	**3.2%**	$ 47.16	53.8%	$ 30.67

Fuel for power generation costs increased in 2004 as compared to 2003. The increase in average fuel cost was due to increases in natural gas prices which were partially offset by decreases in coal prices. The increase in the volume of generation was primarily due to SPPC satisfying more of its native load requirements through its own generation. This increase in generation was partially offset by 2 months of down time from unscheduled maintenance at the Ft. Churchill and Piñon Pine Generating Units during the fall of 2004.

Fuel for power generation costs increased in 2003 as compared to 2002 due to increases in natural gas prices. Partially offsetting these increases was a reduction in volume due to lower system load requirements.

Gas Purchased for Resale

	2004		2003		2002
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
GAS PURCHASED FOR RESALE	**$121,526**	**8.8%**	$111,675	21.4%	$91,961
Gas purchased for resale (in thousands of decatherms)	**17,673**	**-11.5%**	19,964	11.3%	17,930
Average cost per decatherm	**$ 6.88**	**23.1%**	$ 5.59	9.0%	$ 5.13

The cost of gas purchased for resale increased in 2004 as compared to 2003 due to increases in natural gas prices. In addition, transportation costs increased in 2004 due to the expiration of the Southwest Gas reservation fee contract in September 2003. The decrease in volume is due to customers leaving the SPPC gas system, therefore reducing the volume of gas required for wholesale activities.

The cost of gas purchased for resale increased in 2003 as compared to 2002 as a result of higher unit prices and an increase in quantities purchased. The increase in quantities purchased was the result of an increase in the availability of gas for wholesale activities. The higher unit prices were attributable to increased demand for gas in the Pacific Northwest and additional transportation fees.

Deferral of Energy Costs—Net

	2004		2003		2002
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
Deferred energy costs disallowed	**$ —**	**N/A**	$45,000	-21.0%	$ 56,958
Deferred energy costs—electric—net	**7,060**	**N/A**	1,982	N/A	(54,632)
Deferred energy costs—gas—net	**(4,136)**	**N/A**	16,155	-34.8%	24,785
Total	**$ 2,924**		$63,137		$ 27,111

Deferred energy costs disallowed for the year ended December 31, 2003, represents a write-off effective June 1, 2003, of $45 million pursuant to a stipulation approved by the PUCN in Docket 03-1014. Deferred energy costs disallowed for the year ended December 31, 2002 reflects the write-off of $53 million of electric deferred energy costs, disallowed by the PUCN in its May 28, 2002 decision, and a write-off of $4 million in gas costs, disallowed by the PUCN in its December 23, 2002 decision on SPPC's Purchase Gas Adjustment rate case.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

Deferred energy costs—net includes the amortization of approved deferred energy costs included in current rates and the under or over-collection of current period energy costs. An under-collection exists when actual energy costs exceed energy revenues currently being recovered in rates. To the extent that actual costs exceed the amounts recoverable in current rates the difference is recognized as a reduction in recorded costs. Conversely, an over-collection exists when actual energy costs are less than energy revenues currently being recovered in rates resulting in the difference being recognized as an increase in recorded costs. Reference Note 1, Summary of Significant Accounting Policies, Deferral of Energy Costs of the Notes to Financial Statements for further detail of deferred energy balances.

Deferred energy costs—electric—net for 2004, 2003, and 2002 reflect amortization of deferred energy costs of $36.6 million, $45.5 million, and $30.2 million, respectively; and an under-collection of amounts recoverable in rates of $29.6 million, $43.5 million, and $84.8 million, respectively.

Deferred energy costs—gas—net for 2004, 2003, and 2002 reflect amortization of deferred energy costs of $3.3 million, $13.1 million, and $13.2 million, respectively; and an under-collection of amounts recoverable in rates in 2004 of $7.4 million and over-collections in 2003 and 2002 of $3.1 million and $11.6 million, respectively.

Allowance For Funds Used During Construction (AFUDC)

	2004		2003		2002
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
Allowance for other funds used during construction	**$1,718**	**-41.2%**	$2,920	N/A	$ 117
Allowance for borrowed funds used during construction	**2,849**	**-13.0%**	3,276	76.3%	1,858
	$4,567	**-26.3%**	$6,196	N/A	$1,975

AFUDC for SPPC is lower in 2004 compared to 2003 due to a decrease in the Construction Work-In-Progress (CWIP) balance on which AFUDC is calculated, offset by an increase in the AFUDC rate. The decrease in CWIP resulted from the completion of the Falcon-Gonder 345KV Transmission Line. AFUDC is higher in 2003 compared to 2002 due to an increase in the AFUDC rates and an increase in CWIP.

Other (Income) and Expenses

	2004		2003		2002
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
Other operating expense	**$128,091**	**10.1%**	$116,390	9.7%	$106,122
Maintenance expense	**$ 21,877**	**2.2%**	$ 21,410	-7.9%	$ 23,240
Depreciation and amortization	**$ 86,806**	**6.5%**	$ 81,514	6.7%	$ 76,373
Income tax expense/(benefit)	**$ 14,978**	**N/A**	$ (13,704)	98.0%	$ (6,922)
Interest charges on long-term debt	**$ 71,312**	**-6.2%**	$ 76,002	14.3%	$ 66,474
Interest on terminated contracts (Note 14)	**$ (10,999)**	**N/A**	$ 14,453	N/A	$ 1,463
Interest charges—other	**$ 5,367**	**-39.8%**	$ 8,914	-3.1%	$ 9,200
Interest accrued on deferred energy	**$ (5,133)**	**-0.6%**	$ (5,163)	-51.5%	$ (10,644)
Other income	**$ (3,406)**	**-22.6%**	$ (4,403)	3.2%	$ (4,266)
Disallowed merger costs	**$ 1,929**	**N/A**	$ —	N/A	$ —
Plant costs disallowed	**$ 47,092**	**N/A**	$ —	N/A	$ —
Other expense	**$ 5,726**	**-15.4%**	$ 6,767	2.9%	$ 6,577
Income taxes—other income and expense	**$ (14,653)**	**N/A**	$ 1,467	-39.7%	$ 2,431

The increase in Other operating expense during 2004 compared to 2003 was primarily due to amortization expense that is being recovered through rates for merger, goodwill and divestiture costs. Additional contributing factors include increased transmission and distribution activities along with bank charges associated with SPPC's revolving credit facility, advisor and legal fees. These increases were offset by less provisions for uncollectible retail customer accounts.

The increase in Other operating expense during 2003 compared to 2002 resulted primarily from increased provisions for uncollectible retail customer accounts of approximately $5.3 million, the recognition of short-term incentive compensation plan costs during 2003, higher operating costs at the Valmy and Tracy generating facilities, and higher insurance premiums.

Maintenance expense in 2004 was comparable to the prior year. The decrease in 2003 maintenance expense compared to 2002 was a result of less miscellaneous maintenance activities performed during 2003.

Depreciation and amortization were higher in 2004 than 2003 due to an increase in plant-in-service. This increase was driven by the completion of the Falcon-Gonder 345KV Transmission Line, offset by a PUCN-mandated write-off of the Piñon Pine facility. Depreciation and amortization were higher in 2003 than 2002 due to an increase in plant-in-service.

Income tax expense/(benefit) changed from income tax benefits recognized for the year ended December 31, 2003 to income tax expense recognized during the same period in 2004. The 2004 income tax expense was recognized due to SPPC's pre-tax net income in 2004 compared to a pre-tax net loss in 2003. Additionally, a flow-through tax benefit for tax deductible pension contributions was recognized in 2004 of $3.7 million. This change in income is due to an increase in operating revenue, offset by a decrease in operating expenses (including purchased power), as well as a decrease in interest charges on terminated contracts in 2004. See Note 14, Commitments and Contingencies of the Notes to Financial Statements for discussion on interest on terminated contracts. See Note 11, Income Taxes of the Notes to Financial Statements for additional information regarding the computation of income taxes.

SPPC's interest charges on Long-Term Debt for the year ended December 31, 2004 decreased from 2003 as a result of lower long-term debt balances after the redemption, in December 2003 of $18 million debt, the reduction in interest rate during 2004 associated with the replacement of its 10.5% $100 million three year notes with 6.25% $100 million Series H Notes, and a reduction in interest rate in April 2004, of SPPC's $80 million Washoe Water Bonds from 7.5% to 5.0%. SPPC's interest charges on Long-Term Debt for the year ended December 31, 2003, increased over the same period, 2002 due to the issuance in October 2002 of $100 million of additional debt at an interest rate of 10.5% and the remarketing in May 2003 of $80 million of Washoe County Water Bonds at a higher interest rate.

Interest charges on terminated contracts for the year ended December 31, 2004 reflects the reversal of interest of $12.3 million resulting from a ruling by the U.S. District Court hearing the utilities appeal against the Bankruptcy Court's ruling in the bankruptcy proceedings of Enron Power Marketing (Enron). In September 2003, SPPC recorded $12.4 million of additional interest costs on terminated contracts as a result of a final judgment issued on September 26, 2003, by the Bankruptcy Court Judge overseeing the bankruptcy proceedings of Enron. See Note 14, Commitments and Contingencies, of the Notes to Financial Statements for more information regarding the Enron litigation.

Interest charges—other for the year ended December 31, 2004 decreased compared to the same period in 2003 following reduced charges related to SPPC's short-term credit facilities. These facilities were replaced during 2004 with long-term facilities; when drawn upon, interest related to the new facilities is chargeable to long-term debt interest.

Interest accrued on deferred energy costs for the year ended December 31, 2004, was slightly lower than the same period in 2003. Higher deferred energy balances and rates prevalent during the second half of 2004 were offset by lower balances during the first half, when compared to the same periods in 2003. Lower deferred energy balances during 2003, compared to 2002, resulted in lower interest being accrued during the year ended December 31, 2003, compared to the same period in 2002. (Refer to Regulatory Proceedings for discussion of deferred energy issues).

SPPC's Other income decreased for the year ended December 31, 2004, compared to the same period in 2003 due to lower interest income and the gain recognized in 2003 from the sale of non-utility property. SPPC's Other income increased slightly for the year ended December 31, 2003, compared to the same period in 2002 due primarily to gains recognized from the sale of non-utility property and an increase in lease revenues. The increase was partially offset by a decrease in interest income.

Disallowed merger costs expense for the year ended December 31, 2004, includes the write-off of costs that resulted from the merger between SPR and NPC, allocable to non-Nevada jurisdictional electricity sales, which were determined not to be recoverable in future rates.

SPPC's Plant costs disallowed is the result of the decision by the PUCN to disallow recovery of a portion of the costs associated with the Piñon Pine power plant project. See Note 3, Regulatory Actions of the Notes to Financial Statements for details.

SPPC's Other expense for the year ended December 31, 2004 decreased from the same period 2003, following lower expenses associated with assistance programs, corporate advertising, and lobbying activities. These reductions were partially offset by costs associated with SPPC'S Supplementary Executive Retirement Plan which were disallowed by the PUCN in 2004. SPPC's Other expense for the year ended December 31, 2003 was comparable to the same period in 2002. Higher expense was recognized during 2003 related to SPPC's general office building and advertising and was substantially offset by charges during 2002 related to SPPC's divestiture of its water division.

Income taxes—other income and expense changed from income tax expense recognized for the year ended December 31, 2003 to income tax benefits recognized during the same period in 2004. The 2004 tax benefit was recognized primarily as a result of an impairment charge associated with the Piñon Pine generating facility during the second quarter of 2004. See Note 3, Regulatory Actions of the Notes to the Financial Statements for additional information regarding the impairment charge.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

ANALYSIS OF CASH FLOWS

SPPC's cash flows improved during 2004, when compared to 2003, due mainly to rate increases that went into effect in the second quarter of 2004 to recover deferred energy balances and operating costs. Also contributing to this increase was reduced construction expenditures as a result of the completion of the Falcon to Gonder project, a reduction in interest payments due to successful remarketing efforts and no dividends being paid to SPR. Partially offsetting these increases were a payoff of short-term borrowing of $25 million in March 2004, a payment of $11 million into the Enron escrow account ordered by the judge overseeing the Enron bankruptcy proceedings and funding for the pension plan.

SPPC had lower cash flows in 2003, when compared to 2002, as a result of decreases in cash from operating, investing, and financing activities. Cash flows from operating activities during 2003 were lower primarily as a result of an income tax refund received in 2002, the prepayment and accelerated payment of fuel and energy purchases during 2003 and higher interest costs. Cash used by investing activities increased in 2003 due to the construction of the Falcon to Gonder transmission line. SPPC utilized internally generated cash to fund construction in 2003 and reduced its dividend payments to SPR due to its weakened financial condition, which resulted in a net decrease in cash flows from financing activities when compared to 2002.

LIQUIDITY AND CAPITAL RESOURCES

SPPC had cash and cash equivalents of approximately $19 million at December 31, 2004.

SPPC anticipates capital requirements for construction costs in 2005 will be approximately $176.6 million. SPPC expects to finance its capital requirements with a combination of internally generated funds, including the recovery of deferred energy, and the use of existing credit facilities.

Mortgage Indentures

SPPC's First Mortgage Indenture creates a first priority lien on substantially all of SPPC's properties in Nevada and California. As of December 31, 2004, $487.3 million of SPPC's first mortgage bonds were outstanding. SPPC agreed in its General and Refunding Mortgage Indenture that it would not issue any additional first mortgage bonds.

SPPC's General and Refunding Mortgage Indenture creates a lien on substantially all of SPPC's properties in Nevada that is junior to the lien of the first mortgage indenture. As of December 31, 2004, there were $420 million of SPPC's General and Refunding Mortgage securities outstanding. Additional securities may be issued under the General and Refunding Mortgage Indenture on the basis of:

(1) 70% of net utility property additions,

(2) the principal amount of retired General and Refunding Mortgage bonds, and/or

(3) the principal amount of first mortgage bonds retired after April 8, 2002.

On the basis of (1), (2), and (3) above, as of October 31, 2004, SPPC had the capacity to issue approximately $344 million of additional General and Refunding Mortgage securities.

Although SPPC has substantial capacity to issue additional General and Refunding Mortgage securities on the basis of property additions and retired securities, the financial covenants contained in the Revolving Credit Agreement limit the amount of additional indebtedness that SPPC may issue and the reasons for which such indebtedness may be issued.

SPPC also has the ability to release property from the liens of the two mortgage indentures on the basis of net property additions, cash and/or retired bonds. To the extent SPPC releases property from the lien of its General and Refunding Mortgage Indenture, it will reduce the amount of bonds issuable under that indenture.

Financing Transactions

Short-Term Financings

On October 22, 2004, SPPC terminated its $50 million long-term revolving credit facility, which had been established on May 4, 2004, and replaced it with a three year revolving credit facility of $75 million. In this new credit facility, $25 million of the $75 million is short-term (364 day) until such time as the utility receives long-term debt authority from the PUCN for the additional $25 million. SPPC has not yet determined whether it will seek such long-term authority.

On January 30, 2004, SPPC issued its General and Refunding Mortgage Note, Series G, due March 31, 2004, in the maximum principal amount of $22 million under a revolving Credit Agreement with Lehman Commercial Paper Inc. Borrowings under the Series G Note were to be used to provide back-up liquidity for SPPC during its 2003-2004 winter peak. This credit facility was never used prior to its maturity on March 31, 2004.

On December 22, 2003, SPPC issued and sold its $25 million General and Refunding Mortgage Notes, Series F, due March 31, 2004 in order to provide additional liquidity for SPPC's fuel and power purchases during its 2003-2004 winter peak. The notes were paid off in March 2004.

Revolving Credit Facility

On October 22, 2004, SPPC entered into a $75 million Credit Agreement with Union Bank of California, N.A., as Administrative Agent. Borrowings under this revolving credit facility will be used for SPPC's general corporate purposes. Unless SPPC seeks long-term authority for the incremental $25 million current short-term portion; this facility would be reduced to $50 million in October 2005.

The revolving credit facility, which is secured by SPPC's $75 million General and Refunding Mortgage Bond, Series L, will expire on October 22, 2007. The rate for outstanding loans and/or letters of credit under revolving credit facility will be at either an alternate base rate or a Eurodollar rate plus a margin that varies based upon SPPC's credit rating by S&P and Moody's. Currently, SPPC's alternate base rate margin is 1% and its Eurodollar margin is 2%. SPPC has not borrowed any amounts under this revolving credit facility.

Upon the effectiveness of the Credit Agreement, SPPC terminated its previously existing $50 million revolving credit facility, which it entered into on May 4, 2004. No amounts were outstanding under this facility at the time of termination.

The SPPC Credit Agreement contains two financial maintenance covenants. The first requires that SPPC maintain a ratio of consolidated indebtedness to consolidated capital, determined as of the last day of each fiscal quarter, not to exceed 0.68 to 1. The second requires that SPPC maintain a ratio of consolidated cash flow to consolidated interest expense, determined as of the last day of each fiscal quarter for the period of four consecutive fiscal quarters, not to be less than 2.0 to 1.

Due to a negative pledge obligation in SPPC's Series E Bond, which was issued to an escrow agent to secure Enron's judgment against SPPC (see Note 14, Commitments and Contingencies of the Notes to Financial Statements), SPPC amended its Series E Bond to include these two financial maintenance covenants. Although the judgment was vacated in a decision handed down on October 10, 2004 by the U.S. District Court for the Southern District of New York, SPPC's Series E Bond will continue to remain in escrow through the pendency of all remands and appeals pursuant to a stipulation and agreement previously entered into among NPC, SPPC, and Enron.

The Credit Agreement, similar to SPPC's Series H Notes and Series E Bond, limits the amount of payments in respect of common stock dividends that SPPC may pay to SPR. This limitation is discussed in Note 9, Dividend Restrictions of the Notes to Financial Statements.

The Credit Agreement also contains a restriction on SPPC's ability to incur additional indebtedness and among other things, restrictions on liens (other than permitted liens, which include liens to secure certain permitted debt) and certain sale and leaseback transactions. Such restrictions are further discussed in Note 9, Dividend Restrictions of the Notes to Financial Statements.

The Credit Agreement provides for certain events of default including any of the following events: SPPC fails to make payments of principal or interest under the Credit Agreement, SPPC fails to comply with certain agreements included in the Credit Agreement, SPPC files for bankruptcy, or a change of control occurs. The Credit Agreement also provides for an event of default if a judgment of $15 million or more is entered against SPPC and such judgment is not vacated, discharged, stayed or bonded pending appeal within 60 days. Since, the Credit Agreement also prohibits the creation or existence of any liens on SPPC's properties except for liens specifically permitted under the Credit Agreement, if a judgment lien is filed against SPPC, the filing of the lien will trigger an event of default under the Credit Agreement. The Credit Agreement also provides for an event of default if SPPC defaults in the payment of principal, interest or premium beyond the applicable grace period under any mortgage, indenture or other security instrument, relating to debt in excess of $15 million.

Upon an event of default, the Administrative Agent under the SPPC Credit Agreement may, upon request of more than 50% of the lenders under the Credit Agreement, declare all amounts due under the Credit Agreement immediately due and payable. Since SPPC's obligations under the Credit Agreement are secured by its General and Refunding Mortgage Bond, if SPPC fails to repay all amounts due upon an acceleration of the Credit Agreement within three business days, such failure will be deemed a default in the payment of principal and will trigger an event of default under the SPPC General and Refunding Mortgage Indenture that would be applicable to all securities issued under the SPPC General and Refunding Mortgage Indenture.

$50 Million Revolving Credit Facility

On May 4, 2004, SPPC established a $50 million Revolving Credit Facility with a maturity date of May 4, 2008. Borrowings under this facility were evidenced on SPPC's General and Refunding Mortgage Bond, Series K, due 2008.

Concurrent with the establishment of its new $75 million revolving credit facility, discussed above, this existing facility was terminated on October 22, 2004. No amounts were outstanding under this facility at the time of termination.

Water Facilities Refunding Revenue Bonds

On May 3, 2004, SPPC's $80 million Washoe County, Nevada, Water Facilities Refunding Revenue Bonds, Series 2001, were successfully remarketed. The interest rate on the bonds was adjusted from their prior one year 7.50% term rate to a 5.0% term rate for the period of May 3, 2004 to and including July 1, 2009. The bonds will be subject to remarketing on July 1, 2009. In the event that the bonds cannot be successfully remarketed on that date, SPPC will be required to purchase the outstanding bonds at a price of 100% of principal amount plus accrued interest. From May 3, 2004 to and including July 1, 2009, SPPC's payment and purchase obligations in respect of the bonds are secured by SPPC's $80 million General and Refunding Mortgage Note, Series J, due 2009.

General and Refunding Mortgage Notes, Series H

On April 16, 2004, SPPC issued and sold $100 million of its 6¼% General and Refunding Mortgage Notes, Series H, due April 15, 2012. The Series H Notes, which were issued with registration rights, were exchanged for registered notes in October 2004. The proceeds of the issuance along with operating cash were used to substantially pay off SPPC's 10.5% Term Loan Facility, due October 2005.

The Series H Notes, similar to SPPC's Series E Bond, limit the amount of payments in respect of common stock dividends that SPPC may pay to SPR. This limitation is discussed in Note 9, Dividend Restrictions of the Notes to Financial Statements.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

The terms of the Series H Notes, as with the Series E Bond, also restrict SPPC from incurring any additional indebtedness unless:

(1) at the time the debt is incurred, the ratio of consolidated cash flow to fixed charges for SPPC's most recently ended four quarter period on a pro forma basis is at least 2.0 to 1, or

(2) the debt incurred is specifically permitted under the terms of the Series H Notes, which includes certain credit facility or letter of credit indebtedness, obligations incurred to finance property construction or improvement, indebtedness incurred to refinance existing indebtedness, certain intercompany indebtedness, hedging obligations, indebtedness incurred to support bid, performance or surety bonds, and certain letters of credit issued to support SPPC's obligations with respect to energy suppliers, or

(3) indebtedness incurred to finance capital expenditures pursuant to SPPC's 2004 Integrated Resource Plan.

If SPPC's Series H Notes are upgraded to investment grade by both Moody's and S&P, these restrictions will be suspended and will no longer be in effect so long as the Series H Notes remain investment grade.

Among other things, the Series H Notes also contain restrictions on liens (other than permitted liens, which include liens to secure certain permitted debt) and certain sale and leaseback transactions. In the event of a change of control of SPPC, the holders of these securities are entitled to require that SPPC repurchase their securities for a cash payment equal to 101% of the aggregate principal amount plus accrued and unpaid interest.

Term Loan Agreement

On October 30, 2002, SPPC entered into a $100 million Term Loan Agreement with several lenders and Lehman Commercial Paper Inc., as Administrative Agent. The net proceeds of $97 million from the Term Loan Facility, along with available cash, were used to pay off SPPC's $150 million credit facility, which was secured by SPPC's Series B General and Refunding Mortgage Bond. The Term Loan Facility, which is secured by SPPC's $100 million Series C General and Refunding Mortgage Bond, will expire October 31, 2005.

In April 2004 the Term Loan was paid off and the Term Loan Agreement was terminated.

Accounts Receivable Facility

On October 29, 2002, SPPC established an accounts receivable purchase facility of up to $75 million. On May 4, 2004, SPPC delivered a notice of termination of its accounts receivable facility in connection with the establishment of its new revolving credit facility. The termination was effective on May 19, 2004.

Financial Covenants

SPPC's $75 million Revolving Credit Agreement dated October 22, 2004, contains two financial maintenance covenants. The first requires that SPPC maintain a ratio of consolidated indebtedness to consolidated capital, determined as of the last day of each fiscal quarter, not to exceed 0.68 to 1. The second requires that SPPC maintain a ratio of consolidated cash flow to consolidated interest expense, determined as of the last day of each fiscal quarter for the period of four consecutive fiscal quarters, not to be less than 2.0 to 1.

Due to a negative pledge obligation in SPPC's $92 million General and Refunding Mortgage Bond, Series E, SPPC amended its Series E Bond to include these two financial maintenance covenants. SPPC's Series E Bond, which is currently held by an escrow agent, was issued to secure the Enron Judgment (see Note 14, Commitments and Contingencies of the Notes to Financial Statements for a discussion of the Enron Judgment).

Cross-Default Provisions

None of the financing agreements of SPPC contain a cross-default provision that would result in an event of default by SPPC upon an event of default by SPR or NPC under any of its financing agreement. In addition, certain financing agreements of SPPC provide for an event of default if there is a failure under other financing agreements of SPPC to meet payment terms or to observe other covenants that would result in an acceleration of payments due. Most of these default provisions (other than ones relating to a failure to pay other indebtedness) provide for a cure period of 30-60 days from the occurrence of a specified event during which time SPPC may rectify or correct the situation before it becomes an event of default. The primary cross-default provisions in SPPC's various financing agreements are briefly summarized below:

- SPPC's General and Refunding Mortgage Indenture, under which SPPC has $420 million of securities outstanding (excluding SPPC's Series E Bond, which is held in escrow in connection with the Enron Litigation) as of December 31, 2004, provides for an event of default if a matured event of default under SPPC's First Mortgage Indenture occurs;
- The terms of SPPC's Series H Notes and Series E Bond provide that a default with respect to the payment of principal, interest or premium beyond the applicable grace period under any mortgage, indenture or other security instrument, by SPPC or any of its restricted subsidiaries, relating to debt in excess of $15 million, triggers a right of the holders of the Series H Notes and the Series E Bond to require SPPC to redeem their series of Notes or Bonds, at a price equal to 100% of the aggregate principal amount plus accrued and unpaid interest and liquidated damages, if any, upon notice given by at least 25% of the outstanding noteholders for such series of Notes or Bonds; and
- SPPC's $75 million Credit Agreement provides for an event of default if SPPC defaults in the payment of principal, interest or premium beyond the applicable grace period under any mortgage, indenture or other security instrument, relating to debt in

excess of $15 million. Upon an event of default, the Administrative Agent under the SPPC Credit Agreement may, upon request of more than 50% of the lenders under the Credit Agreement, declare all amounts due under the Credit Agreement immediately due and payable. Since SPPC's obligations under the Credit Agreement are secured by its General and Refunding Mortgage Bond, if SPPC fails to repay all amounts due upon an acceleration of the Credit Agreement within three business days, such failure will be deemed a default in the payment of principal and will trigger an event of default under SPPC's General and Refunding Mortgage Indenture that would be applicable to all securities issued under SPPC's General and Refunding Mortgage Indenture.

Judgment Related Defaults

SPPC's Series E Bond, Series H Notes, and Revolving Credit Agreement provide for an event of default if a judgment of $15 million or more is entered against SPPC and such judgment is not paid, discharged, or stayed for a period of 60 days. The Notes, the Bond and Revolving Credit Agreement also prohibit the creation or existence of any liens on SPPC's properties except for liens specifically permitted under the terms of Notes, the Bond or Revolving Credit Agreement.

Since the Series E Bond and Series H Notes were issued under SPPC's General and Refunding Mortgage Indenture and SPPC's Revolving Credit Agreement is secured by a General and Refunding Mortgage Bond, a default under these Notes, the Bond or the Revolving Credit Agreement will trigger a default under SPPC's General and Refunding Mortgage Indenture. If a judgment lien is created on SPPC's real property located in Nevada, SPPC has been advised that the judgment lien would be an interceding lien that would have priority over subsequent advances under SPPC's General and Refunding Mortgage Indenture; therefore, SPPC would be unable to provide certain required opinions of counsel to issue additional securities under its General and Refunding Mortgage Indenture until the judgment lien is discharged and released.

Limitations on Indebtedness

The terms of SPPC's Series E Bond, Series H Notes and Revolving Credit Agreement restrict SPPC from issuing additional indebtedness unless:

(1) at the time the debt is incurred, the ratio of consolidated cash flow to fixed charges for SPPC's most recently ended four quarter period on a pro forma basis is at least 2.0 to 1, or

(2) the debt incurred is specifically permitted under the terms of the Series H Notes, the Series E Bond and the SPPC Revolving Credit Agreement, which includes certain credit facility or letter of credit indebtedness, obligations incurred to finance property construction or improvement, indebtedness incurred to refinance existing indebtedness, certain intercompany indebtedness, hedging obligations, indebtedness incurred to support bid, performance or surety bonds, and certain letters of credit issued to support SPPC's obligations with respect to energy suppliers, or

(3) indebtedness incurred to finance capital expenditures pursuant to SPPC's 2004 Integrated Resource Plan.

Credit Ratings

On March 29 and April 1, 2002, following the decision by the PUCN in NPC's 2001 deferred energy rate case, S&P and Moody's lowered SPPC's unsecured debt ratings to below investment grade. On April 23 and 24, 2002, SPPC's unsecured debt ratings were further downgraded and its secured debt ratings were downgraded to below investment grade. The decision of the PUCN on May 28, 2002, on SPPC's deferred energy application to disallow $53 million of deferred purchased fuel and power costs accumulated between March 1, 2001 and November 30, 2001, did not result in any further downgrades of SPPC's securities.

In connection with the credit ratings downgrades referenced above, SPPC lost its A2/P2 commercial paper ratings and can no longer issue commercial paper. SPPC does not expect to have direct access to the commercial paper market for the foreseeable future.

Energy Supplier Issues—Contract Terminations

In early May of 2002, Enron Power Marketing Inc. (Enron), Morgan Stanley Capital Group Inc. (MSCG), Reliant Energy Services, Inc., and several smaller suppliers terminated their power deliveries to SPPC. These terminating suppliers asserted their contractual right under the WSPP agreement to terminate deliveries based upon SPPC's alleged failure to provide adequate assurance of its performance under the WSPP agreement to any of their suppliers. For further information regarding contract terminations see Note 14, Commitments and Contingencies of the Notes to Financial Statements.

SPPC has established accrued liabilities, included in its Consolidated Balance Sheets as "Contract termination liabilities," of $94 million for terminated power supply contracts and associated interest. Included in SPPC's deferred energy balances as of December 31, 2004, is approximately $84 million of charges associated with the terminated power supply contracts, deferred for recovery in rates in future periods.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

If SPPC is required to pay part or all of the amounts accrued for, SPPC will pursue recovery of the amounts through future deferred energy filings. To the extent that SPPC is not permitted to recover any portion of these costs through a deferred energy filing, the amounts not permitted would be charged as a current operating expense. SPPC has appealed the Enron Bankruptcy Court Judgment to the U.S. District Court of New York.

PUCN Order

On April 8, 2004, the PUCN issued an order in connection with its authorization of the issuance of secured long-term debt securities by SPPC in an aggregate amount not to exceed $230 million. The PUCN order, for Docket 03-12030, approved SPPC's financial application with a restriction on SPPC's ability to dividend funds up to SPR. The restriction does not prohibit SPPC from paying dividends to SPR for amounts necessary for SPR to meet its current and future interest payments requirements. The PUCN order expires December 31, 2005.

Pension Plan Matters

SPR has a qualified pension plan that covers substantially all employees of SPR, NPC, and SPPC. The annual net benefit cost for the plan is expected to decrease in 2005 by approximately $5.6 million compared to the 2004 cost of $28.3 million. As of September 30, 2004, the measurement date, the plan was fully funded. During 2004, SPPC contributed a total of $31.2 million to meet their funding obligations under the plan. At the present time it is not expected that any additional funding will be required in 2005 to meet the minimum funding levels defined by the Pension Benefit Guaranty Corporation.

Construction Expenditures and Financing

The table below provides SPPC's consolidated cash construction expenditures and internally generated cash for the years ended December 31 (dollars in thousands):

	2004	2003	2002
Cash construction expenditures	**$103,476**	$126,585	$ 95,070
Net cash flow from operating activities	**$127,279**	$ 75,167	$175,637
Common and preferred cash dividends paid	**3,900**	22,430	48,805
Internally generated cash	**123,379**	52,737	126,832
Investment by parent company	**—**	—	10,000
Total cash available	**$123,379**	$ 52,737	$136,832
Internally generated cash as a percentage of cash construction expenditures	**119%**	42%	133%
Total cash generated (used) as a percentage of cash construction expenditures	**119%**	42%	144%

SPPC's estimated cash construction expenditures for 2005 through 2009 are $1 billion. Construction expenditures for 2005 are projected to be $176.6 million and are expected to be financed by internally generated funds which include recovery of the deferred energy balances.

SPPC's 2005–2009 capital forecast includes a coal fired generating station during the forecast period. If this project is approved by the PUCN, SPPC believes that its improved financial condition, as evidenced by the bond sales in 2004, should allow it to raise funds in the capital markets. For additional information regarding financing, see Liquidity and Capital Resources.

Contractual Obligations

The table below provides SPPC's contractual obligations, not including estimated construction expenditures described above, as of December 31, 2004, that SPPC expects to satisfy through a combination of internally generated cash and, as necessary, through the issuance of short-term and long-term debt (dollars in thousands):

Payment Due by Period

	2005	2006	2007	2008	2009	Thereafter	Total
Long-term debt maturities	$ 2,400	$ 52,400	$ 2,400	$322,400	$ 600	$ 617,250	$ 997,450
Long-term debt interest payments	69,229	69,272	65,858	53,058	40,258	408,470	706,145
Purchased power	29,602	30,569	31,004	32,699	17,570	—	141,444
Coal and natural gas	152,024	78,014	55,199	48,091	39,215	309,392	681,935
Operating leases	8,641	8,068	6,967	6,787	6,268	43,331	80,062
Total contractual cash obligations	$261,896	$238,323	$161,428	$463,035	$103,911	$1,378,443	$2,607,036

Capital Structure

SPPC's actual consolidated capital structure was as follows at December 31:

	2004		2003	
Short-term debt(1)	**$ 2,400**	**0.1%**	$ 108,400	6.5%
Long-term debt	**994,309**	**56.9%**	912,800	54.8%
Preferred stock	**50,000**	**2.9%**	50,000	3.0%
Common equity	**705,395**	**40.1%**	593,771	35.7%
TOTAL	**$1,752,104**	**100%**	$1,664,971	100%

(1) Includes current maturities of long-term debt and capital lease obligations.

ENERGY SUPPLY (UTILITIES)

The energy supply function at the Utilities encompasses the reliable and efficient operation of the Utilities' owned generation, the procurement of all fuels and purchased power and resource optimization (i.e., physical and economic dispatch). The Utilities have undertaken a rigorous review of the energy supply function and have implemented policy, planning and organizational changes to address the dramatic changes that have and are occurring in the energy industry.

The structure of the western wholesale energy market has seen dramatic changes in recent years. Significant among these are the collapse of the energy trading model and the merchant energy sector, which has resulted in reduced liquidity in the traded spot and forward markets for standard products. In addition, a credit crisis in the broader energy sector has resulted in a series of cancellations of new generation projects, putting intermediate term capacity margins in the broader region and within both Utilities' sub-region in jeopardy.

The Utilities also face energy supply challenges for their respective load control areas. There is the potential for continued price volatility in each Utility's service territory, particularly during peak periods. A greater dependence on gas-fired generation in the service territory subjects power prices to gas price volatilities. Both Utilities face load obligation uncertainty due to the potential for customer switching. Counterparties in these areas have significant credit difficulties, representing credit risk to the Utilities. Finally, each Utility's own credit situation can have an impact on its ability to enter into transactions.

In response to these energy supply challenges, the Utilities have adopted an approach to managing the energy supply function that has three primary elements. The first element is a set of management guidelines to procuring and optimizing the supply portfolio that is consistent with the requirements of a load serving entity with a full requirements obligation. The second element is an energy risk management and risk control approach that ensures clear separation of roles between the day-to-day management of risks and compliance monitoring and control; and ensures clear distinction between policy setting (or planning) and execution. Lastly, the Utilities will pursue a process of ongoing regulatory involvement and acknowledgement of the resource portfolio management plans.

Energy Supply Planning

Within the energy supply planning process, there are three key components covering different time frames:

(1) the PUCN-approved long-term IRP has a twenty-year year planning horizon;

(2) the energy supply plan, which is an intermediate term resource procurement and risk management plan that establishes the supply portfolio parameters within which intermediate term resource requirements will be met, has a one-to-three year planning horizon; and

(3) tactical execution activities with a one-month to twelve-month focus.

The energy supply plan operates in conjunction with the PUCN-approved twenty-year IRP. It will serve as a guide for near-term execution and fulfillment of energy needs. When the energy supply plan calls for executing contracts with a duration of more than three years, the IRP requires PUCN approval as part of the integrated resource planning process.

In developing energy supply plans and implementing on those plans, management guidelines followed by the Utilities include:

- Maintaining an energy supply plan that balances costs, risks, price volatility, reliability and predictability of supply.
- Investigating feasible commercial options to implement against the energy supply plan.
- Applying quantitative techniques and diligence commensurate with risk to evaluate and execute each transaction.
- Implementing the approved energy supply plan in a manner that manages ratepayer risk in terms of reliability, volatility and cost.
- Monitoring the portfolio against evolving market conditions and managing the resource optimization options.
- Ensuring simple, transparent and well-documented decisions and execution processes.

Energy Risk Management and Control

The Utilities' efforts to manage energy commodity (electricity, natural gas, coal and oil) price risk are governed by a Board of Directors' revised and approved Enterprise Risk Management and Control Policy. That policy created the Enterprise Risk Oversight Committee (EROC) and made that committee responsible for the overall policy direction of the Utilities' risk management and control efforts. That policy further instructed the EROC to oversee the development of appropriate risk management and control policies including the Energy Supply Risk Management and Control Policy.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

The Utilities' commodity risk management program establishes a control framework based on existing commercial practices. The program creates predefined risk limits and delineates management responsibilities and organizational relationships. The program requires that transaction accounting systems and procedures be maintained for systematically identifying, measuring, evaluating and responding to the variety of risks inherent in the Utilities' commercial activities. The program's control framework consists of a disclosure and reporting mechanism designed to keep management fully informed of the operation's compliance with portfolio and credit limits.

The Utilities, through the purchase and sale of financial instruments and physical products, maintain an energy risk management program that limits energy risk to levels consistent with energy supply plans approved by the Chief Executive Officer and the EROC.

Regulatory Issues

The Utilities' long-term IRPs are filed with the PUCN for approval every three years. Nevada law provides that resource additions approved by the PUCN in the resource planning process are deemed prudent for ratemaking purposes. NPC's IRP was filed in July 2003 and received approval in November 2003. SPPC's IRP was filed in July 2004 and approved on November 18, 2004. Between IRP filings, the Utilities are required to seek PUCN approval for power purchases with terms of three years or greater by filing amendments to prior IRP filings.

The Utilities will also seek regulatory input and acknowledgement of intermediate term energy supply plans. The Utilities feel this is necessary to ensure that the appropriate levels of risks are being mitigated at reasonable costs, the appropriate levels of risks are being retained in the portfolio, and decisions to manage risks with best available information at the point in time when decisions are made are subject to reasonable mechanisms for recovery in rates.

Intermediate Term Energy Supply Plans

The Utilities are in the process of developing and implementing their intermediate term energy supply plans. Those plans cover the years 2005 through 2007 and require EROC and the CEO approval prior to implementation. The energy supply plans will operate within the framework of the PUCN-approved twenty-year IRPs. They serve as a guide for near-term execution and fulfillment of energy needs. When the energy supply plans call for the execution of contracts of duration of more than three years, an amended IRP will be prepared and submitted for PUCN approval. The energy supply plans will be updated and filed with the PUCN annually on or before September 1 of each year when not included in an IRP.

NPC's energy supply plan was filed with the PUCN on September 1, 2004 and approved on December 28, 2004. SPPC's plan was filed July 1, 2004 as part of the IRP and approved in November, 2004.

The Utilities intermediate-term portfolio mix shall consist of peaking and seasonal capacity, or synthetic tolling based contracts (i.e., power prices indexed to gas prices), to meet the following requirements:

- Optimize the tradeoff between overall fuel and purchase power cost and market price risk.
- Pursue in-region capacity to enhance long-term regional reliability.
- Represent the set of transactions/products available in the market.
- Reduce credit risk—in a market with weak counter-party financials.
- Procure to match the difficult load profile, to the extent possible.
- Hedge the gas price risk exposure in the fuel portfolio through the purchase of call options.
- Manage off-peak and shoulder month energy price risk through ongoing intermediate and short-term optimization activities (e.g., optimizing the dispatch of NPC generation and/or buying directly from the market).

Both of the energy supply plans represent a change in procurement strategy from previous years. The strategy now focuses on executing contracts for power deliveries to the Utilities' physical points of delivery. In previous years, the Utilities used hedges to reduce price and commodity risk for future purchases by executing power contracts at so-called "liquid" trading points. A typical hedge transaction involved the purchase of power at one of the major trading hubs where prices were highly correlated with a physical delivery point to the Utility. The hedged purchase was either delivered to the Utilities' service territories to service their customers or, if the hedged purchase was not needed to fulfill power requirements, resold in the liquid market. With the significant drop in liquidity in wholesale markets, the Utilities have changed their procurement strategy to focus on power deliveries to the Utilities' physical points of delivery.

Long-Term Purchase Power Activities

In January 2003, NPC entered into long-term purchase agreements with three companies—Panda Gila River LP, Calpine Energy Services, and Mirant Americas Energy Marketing LP. All of the agreements involve energy deliveries to NPC's control area.

The agreement with Panda Gila River LP (PGR) provides 200 MW of power to be delivered from Gila River Power Station in Gila Bend, Arizona, during the summer months of 2003, 2004, and 2005. Due to financial uncertainties of PGR, they provided NPC with a letter of credit to secure their obligations under the agreement. Further, PGR has waived under certain conditions its right to receive financial assurances or security from NPC.

Calpine Energy Services, a wholly owned subsidiary of Calpine Corporation, agreed to deliver 100 MW of energy between the hours of 9 a.m. and midnight and 50 MW of energy from 1 a.m. to 8 a.m., seven days a week from June 1, 2003 through May 31, 2006. Energy is delivered from Calpine's South Point Energy Center.

The arrangement with Mirant involves three separate agreements under which Mirant provides a total of 325 MW of capacity and energy to NPC. Each agreement identifies specific delivery dates ranging from May of 2003 and continuing through April of 2008. A majority of the energy (225 MW) is delivered from the Apex facility located near Las Vegas. In July 2003, Mirant filed for bankruptcy. As such, NPC became part of Mirant's Counterparty Assurance Program (CAP) which entitles NPC to the benefit of a pool of collateral in the event that Mirant fails to deliver under its purchased power contract. The CAP has been approved by the U.S. Bankruptcy Court overseeing Mirant's bankruptcy proceedings, which should provide a higher level of assurance for delivery of energy.

The above agreements were approved by the PUCN on April 14, 2003.

On December 19, 2003, NPC entered into a ten-year 224 MW purchase power agreement with the Las Vegas Cogeneration II facility owned by Black Hills Power and Light and located in North Las Vegas. The agreement was filed with the PUCN for approval on December 23, 2003 and approved in March, 2004. Deliveries of power to NPC will begin on the first day of the month following PUCN approval.

The companies also entered into long-term contracts with renewable energy providers. These contracts are noted in the renewable section of this document.

Short-Term Resource Optimization Strategy

The Utilities' short-term resource optimization strategy involves both day-ahead (next day through the end of the current month) and real-time (next hour through the end of the current day) activities that require buying, selling and scheduling power resources to determine the most economical way to produce or procure the power resources needed to meet the retail customer load. After connecting generation units to the system, the Utilities dispatch the generation output based on the comparative economics of generation versus spot-market purchase opportunities and determine the amount of excess capacity, which is then sold on the wholesale market, or the amount of deficiency capacity, which must be procured on an hourly basis.

The day-ahead resource optimization begins with an analysis of projected loads and existing resources. Firm forward take-or-pay contracts are scheduled and counted towards meeting the capacity needs of the day being pre-scheduled. Any deficiency in the projected operating reserve for the next day, after consideration of available internal generation resources, is met by additional firm purchased power resources. The day-of resource optimization involves minimizing system production costs each hour by either changing the generation output or buying needed power and/or selling excess power in the wholesale market. Any sale of excess power priced above the incremental cost of producing such power reduces the net production cost of operating the electrical system and thereby benefits the end use customer. The Utilities endeavor to reduce the electrical systems' net production cost by selling the available excess power resources.

Real-time resource optimization requires an hourly determination of whether to run generation or purchase power in order to achieve the lowest production costs by calculating the projected incremental or detrimental cost of generation required to meet the forecast load in comparison to obtaining power in the wholesale power market. In the event that committed generators suffer a forced outage that is expected to last through the remaining monthly period, the operating cost of the next available generation resource is compared to purchase power options to determine the lowest cost option.

REGULATORY PROCEEDINGS (UTILITIES)

The Utilities are subject to the jurisdiction of the PUCN and, in the case of SPPC, the CPUC with respect to rates, standards of service, siting of and necessity for generation and certain transmission facilities, accounting, issuance of securities and other matters with respect to electric distribution and transmission operations. NPC and SPPC submit Integrated Resource Plans (IRPs) to the PUCN for approval.

Under federal law, the Utilities and TGPC are subject to certain jurisdictional regulation, primarily by the FERC. The FERC has jurisdiction under the Federal Power Act with respect to rates, service, interconnection, accounting and other matters in connection with the Utilities' sale of electricity for resale and interstate transmission. The FERC also has jurisdiction over the natural gas pipeline companies from which the Utilities take service.

As a result of regulation, many of the fundamental business decisions of the Utilities, as well as the rate of return they are permitted to earn on their utility assets, are subject to the approval of governmental agencies. The following regulatory proceedings have affected, or are expected to affect the utilities financial positions, results of operations and cash flows.

Nevada Matters

Nevada Power Company 2003 General Rate Case

NPC filed its biennial General Rate Case on October 1, 2003, as required by law. On March 26, 2004, the PUCN issued an order allowing $48 million of the $133 million rate increase requested by NPC. The general rate decision reflects the following significant items:

- A Return on Equity (ROE) of 10.25%, and an overall Rate of Return (ROR) of 9.03%, an improvement over NPC's previous ROE and ROR, which were 10.1% and 8.37%, respectively. NPC had requested an ROE of 12.4% and ROR of 10.0%;
- Approximately $7 million of the $8.8 million of goodwill and merger costs requested to be recovered annually over each of the next two years;
- Approximately $21.4 million of generation divestiture costs to be recovered over an extended period of 8 years;

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

- Approved the establishment of a regulatory asset account to capture costs related to the shutdown of the Mohave Power Plant; and
- Required NPC to file a set of recommended quality of service and customer service measurements to be used in future general rate case proceedings. On July 1, 2004, NPC and SPPC jointly filed with the PUCN their recommended quality of service and customer service measurements. The PUCN opened up an investigatory docket to adjudicate the issues.

The PUCN removed from cost of service various items requested by NPC through its general rates filing including costs associated with NPC's 2003 short-term incentive compensation plan and NPC's request to earn a rate of return on the cash balances NPC maintained to ensure sufficient liquidity to procure power. In addition, the PUCN's decision included a decrease to NPC's general rates to allow NPC's customers to share the benefit of approximately $8.3 million per year for the next two years of gains from recent land sales by NPC.

The PUCN responded to petitions filed by the Bureau of Consumer Protection (BCP) and NPC on May 20, 2004 and June 7, 2004, respectively. The PUCN's May 20 order denied two of the issues on which the BCP requested reconsideration, and granted clarification on the third issue. The clarification addressing rental revenue resulted in an overall reduction in the revenue requirement of $1.6 million. The PUCN's June 7, 2004 order concluded that the petition was granted in part since clarification had been given on the requested issues and denied in part since NPC's requested revisions to the order were not accepted.

Nevada Power Company Deferred Energy Cases

As of December 31, 2004, included in the balance sheet of NPC is approximately $135 million of approved deferred energy costs to be collected in current rates over various periods, as detailed in Note 1, Summary of Significant Accounting Policies, of the Notes to Financial Statements. Additionally, included in the balance sheet as of December 31, 2004, is approximately $116 million filed for in NPC's 2004 Deferred Energy case, discussed below, for which a stipulation recovering all costs was reached on February 22, 2005. The PUCN approved the stipulation in total on March 16, 2005.

2004 Deferred Energy Case

On November 15, 2004, NPC filed an application with the PUCN seeking repayment for purchased fuel and power costs accumulated between October 1, 2003 and September 30, 2004, as required by law. The application seeks to establish a rate to collect accumulated purchased fuel and power costs of $116 million, with a carrying charge. The application requests that the 2004 Deferred Energy Accounting Adjustment (DEAA) recovery begin with the expiration of the 2002 DEAA recovery, which is expected to occur in May 2006 and for the 2004 DEAA recovery period to be 22 months.

The application also requests an increase to the going-forward base tariff energy rate (BTER).

In concert with this 2004 DEAA filing, NPC filed a petition with the PUCN requesting that other pending DEAA rate changes be synchronized to change on April 1, 2005 in order to stabilize rates and reduce the number of rate changes. On December 28, 2004, the PUCN issued an order approving a stipulation reached by all parties that allows NPC to defer previously approved DEAA rate changes until April 1, 2005 coincident with the DEAA rate change that will result from the 2004 DEAA case.

The combined effect of the requested synchronization of multiple rate changes (going forward BTER increase, 2001 DEAA expiration, 2003 DEAA initiation) resulted in a request for an overall rate decrease of 2.4%.

On February 22, 2005, a stipulation of the parties was filed with the PUCN resolving all issues in the case. The stipulation provides for an overall decrease of 0.6% in total rates with no disallowances. The PUCN approved the stipulation in total on March 16, 2005.

2003 Deferred Energy Case

On November 14, 2003, NPC filed an application with the PUCN seeking repayment for purchased fuel and power costs accumulated between October 1, 2002 and September 30, 2003, as required by law. The application sought to establish a rate to collect accumulated purchased fuel and power costs of $93 million. On March 26, 2004, the PUCN granted approval for NPC to increase its going forward energy rate as filed, approved recovery for $89 million of its deferred balance, denied $4 million, and denied NPC's request for a tax gross-up on the equity portion of carrying charges. Of the $4 million disallowed, $1.6 million was charged to income in the current period as the remaining amount had no impact on earnings or was charged to income in prior periods. The PUCN ordered the change in going forward rates to take effect April 1, 2004 and delayed the implementation of the deferred energy balance recovery until January 1, 2005 when recovery of the 2001 deferred balance was expected to have been completed.

On December 28, 2004, the PUCN issued an order approving a stipulation reached by all parties that allows NPC to defer the 2003 DEAA rate change until April 1, 2005, which will be coincident with the DEAA rate change that will result from the 2004 DEAA case (see Nevada Power Company 2004 Deferred Energy Case above).

For further detail of deferred energy cases see Note 3, Regulatory Actions of the Notes to Financial Statements.

Nevada Power Company 2003 Integrated Resource Plan

On July 1, 2003, NPC filed its 2003 IRP with the PUCN. The IRP was prepared in compliance with Nevada laws and regulations and covered the 20-year period from 2003 through 2022. The IRP developed a comprehensive, integrated plan that considered customer energy requirements and proposed the resources to meet those requirements in a manner that was consistent with prevailing market fundamentals. The ultimate goal of the IRP was to balance the objectives of minimizing costs and reducing volatility while reliably meeting the electric needs of NPC's customers.

The IRP also included a three-year action plan that covered calendar years 2004, 2005, and 2006. During this period, NPC proposed a number of specific projects to be completed. NPC proposed building an 80 MW combustion turbine at the Harry Allen power plant site with an in-service date prior to the 2006 summer peak and a 520 MW combined cycle generating turbine, also at the Harry Allen power plant site, with a 2007 in-service date. Delivery of the energy from this new generation to NPC's customers would require a reservation on the Harry Allen-to-Mead 500 kilovolt (kV) transmission line. The construction of this transmission project is required to fulfill existing wholesale transmission contractual obligations to Independent Power Producers located within NPC's control area.

The PUCN approved an order on NPC's IRP on November 12, 2003. In general, the order approved NPC's various requests made in its filing and also imposed additional requirements for various briefings, and required amendments to the IRP if there are delays in the combined cycle units construction, issues with transmission reservations, or difficulties financing the IRP. As such, NPC expected to expend up to approximately $500 million prior to the summer of 2007 for the construction and/or acquisition of generation facilities. NPC acknowledged that if internally generated funds were inadequate, it may need to access the capital markets. NPC has since issued new debt, which is discussed below. See NPC's Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources for a discussion of NPC's financial condition and limitations on NPC's ability to issue additional indebtedness.

Nevada Power Company—Subsequent Material Amendment to its 2003 Integrated Resource Plan

On June 29, 2004, NPC filed its second amendment to its 2003 IRP. The second amendment requested PUCN authorization to acquire a partially completed power plant, the Lenzie project, from Duke Energy for $182 million. This amendment requested approval to substitute the nominally rated 1200 MW Lenzie, which is expected to become operational in early 2006, for the previously approved Harry Allen 520 MW combined cycle generator, which is to come on line in 2007.

Lenzie is comprised of two nominally rated 600 MW combined cycle generators located north of Las Vegas. The filing provides NPC's due diligence work, the contract and finance plan. The estimated cost to complete construction is $376 million making the total cost $558 million.

The PUCN held hearings to consider the Resource Plan amendment and an associated financing filing and rendered an order on September 21, 2004. The PUCN granted NPC's request for a critical facility designation and allowed a 2% enhancement of the authorized ROE to be applied to the rate base associated with the Lenzie construction costs expended after acquisition. The PUCN also granted NPC's request for $500 million in long-term debt authority. The order allows for up to an additional 1% enhanced ROE if the two Lenzie generator units are brought on line early and the gradual elimination of the enhanced ROE if completion is delayed. The order allows NPC to include the plant investments during construction in rate base when NPC files its regularly scheduled general rate cases, which permits NPC to earn a return during construction. The PUCN also granted NPC's request to establish regulatory asset accounts to prevent the erosion of earnings, which otherwise would occur due to regulatory lag. The regulatory asset account will capture the depreciation expense and return on rate base between the time the plant is placed in service and when the plant costs are included in rates.

The transaction with Duke Energy closed on October 13, 2004. A future general rate case will be required before NPC can include the costs for this facility in rates.

Nevada Power Company—Miscellaneous Amendments to its 2003 Integrated Resource Plan

NPC has filed a number of other resource plan amendments, which reaffirm the need for a major transmission line, modify demand side management programs, modify four previously approved renewable energy contracts and request approval of two new contracts for renewable energy credits.

Sierra Pacific Power Company 2003 General Rate Case

SPPC filed its biennial general rate case on December 1, 2003, as required by law. SPPC requested an $87 million increase in the annual revenue requirement for general rates. On April 1, 2004, SPPC, the Staff of the PUCN and other interveners in SPPC's 2003 general rate case negotiated a settlement agreement that resolved most of the issues in the revenue requirement and cost of capital portions of SPPC's case. The agreement, which has been approved by the PUCN, includes the following provisions:

- SPPC was allowed to recover a $40 million increase in annual rates.
- SPPC was allowed a Return on Equity (ROE) of 10.25%, and an overall Rate of Return (ROR) of 9.26%, an improvement over SPPC's previous ROE and ROR, which were 10.17% and 8.61%, respectively. SPPC had sought an ROE of 12.4% and ROR of 10.03%.
- The agreement accepted SPPC's requested accounting treatment as filed in its application for purposes of recording revenues, expenses and assets with the following exception. Accounting issues common to SPPC's general rate case and NPC's general rate case that was decided by the PUCN on March 26, 2004, in Docket No. 03-10001, are treated as set forth in the PUCN's Order on NPC's general rate case, except for merger costs. The accounting treatment for merger costs and goodwill established in the NPC decision will apply to the recovery of these costs by SPPC, except that SPPC will include in rates 100% of the costs as filed until recovery is reset by the PUCN in SPPC's next general rate application.
- Required SPPC to file a set of recommended quality of service and customer service measurements to be used in future general rate case proceedings. On July 1, 2004, SPPC and NPC jointly filed with the PUCN their recommended quality of service and customer service measurements. The PUCN opened up an investigatory docket to adjudicate the issues.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

The parties also reached a stipulated agreement that resolved the rate design issues in the case.

Investments in the Piñon Pine generating facility were not addressed by the stipulation. SPPC had sought recovery of its investment of approximately $96 million ($90 million associated with the Nevada jurisdiction) for costs associated with this facility over an extended period (between 10 and 25 years). The recovery of these costs would be in addition to the $40 million annual increase provided for by the stipulation agreement.

On May 27, 2004, the PUCN issued an order accepting the two stipulations, discussed above, and responding to SPPC's request for recovery of the Piñon investments. The PUCN permitted recovery of approximately $37 million (Nevada jurisdictional) of the costs plus a carrying charge to be amortized over 25 years and approximately $11 million (Nevada jurisdictional) of costs without a carrying charge to be amortized over 10 years. The PUCN order granted a $46.7 million increase to SPPC's general revenues.

As a result of the PUCN order, SPPC evaluated the Piñon Pine generating facility for impairment under the provisions of SFAS No. 90, "Regulated Enterprises—Accounting for Abandonments and Disallowances of Plant Costs." As a result of this evaluation, SPPC recognized an impairment loss of approximately $47 million in the second quarter of 2004. The impairment loss recognized consists of disallowed costs of approximately $43 million and an additional $4 million loss because the PUCN did not permit a carrying charge on $11 million of the costs to be recovered.

SPPC filed a petition for judicial review of the PUCN's Piñon Decision in the Second Judicial District Court of Nevada on June 8, 2004. The petition is based on existing resource planning statutes and regulations as they apply to the Piñon project. The Piñon project was approved by the PUCN in SPPC's 1992 Integrated Resource Plan as presented.

SPPC filed its opening brief in early October, and Answering and Reply briefs were filed in November and December, respectively. SPPC has asked for oral argument to occur in the first quarter of 2005. SPPC cannot predict the timing or outcome of a decision from this court.

Sierra Pacific Power Company Deferred Energy Cases

As of December 31, 2004, included in the balance sheet of SPPC is approximately $51 million and ($746 thousand) for electric and gas, respectively, of approved deferred energy costs to be collected/(refunded) in current rates over various periods, as detailed in Note 1, Summary of Significant Accounting Policies of the Notes to Financial Statements. Additionally, included in the balance sheet as of December 31, 2004, is approximately $28 million filed for in SPPC's 2005 Deferred Energy case, discussed below. For further detail of deferred energy cases see Note 3, Regulatory Actions of the Notes to Financial Statements.

2005 Deferred Energy Case

On January 14, 2005, SPPC filed an application with the PUCN seeking repayment for purchased fuel and power costs accumulated between December 1, 2003 and November 30, 2004, as required by law. The application seeks to establish a rate to collect accumulated purchased fuel and power costs of $28 million, with a carrying charge. The application requests that the 2005 Deferred Energy Accounting Adjustment (DEAA) recovery begin on June 1, 2005, coincident with the expiration of the 2002 & 2003 DEAA recovery, together with the commencement of recovery for the 2004 DEAA balance. SPPC has requested for the 2005 DEAA recovery period to be 24 months.

The application also requests an increase to the going-forward base tariff energy rate (BTER).

The combined effect of the requested synchronization of multiple rate changes (going forward BTER increase, 2002 & 2003 DEAA expiration, 2004 DEAA initiation) resulted in a request for an overall rate increase of approximately 1.85%. The PUCN is expected to rule on this filing the later part of May 2005.

2004 Deferred Energy Case

On January 14, 2004, SPPC filed an application with the PUCN, as required by law, seeking to clear deferred balances for purchased fuel and power costs accumulated between December 1, 2002, and November 30, 2003. The Application requested a deviation from regulation and historic practice and to put in place an asymmetric amortization of the deferred energy balance of approximately $42 million, which would result in recovery of $8 million effective July 2004; $17 million effective July 2005; and $17 million effective July 2006. The Application also requested a deviation from regulation in resetting the BTER. That methodology and its results would result in no change to the currently effective BTER.

On July 7, 2004, the PUCN ruled on the deferred energy case, and approved a full recovery of the fuel and purchased power costs. The PUCN order delayed the start of the deferred balance recovery until April 2005, which corresponds with the expected repayment of previous deferred balances. The PUCN also ordered SPPC to implement a higher BTER rate (the rate paid for going forward energy purchases) than that requested by SPPC. The higher BTER rate represents an overall increase of 4.4% in electric rates for SPPC and became effective July 15, 2004.

For further detail of deferred energy cases see Note 3, Regulatory Actions of the Notes to Financial Statements.

SPPC Natural Gas Distribution 2004 Annual Purchased Gas Cost Adjustment

On May 14, 2004, SPPC filed its annual application for Purchased Gas Cost Adjustment for its natural gas local distribution company. In the application, SPPC asked for an increase of $0.09456 per therm to its Base Purchased Gas Rate to recover its expected going forward gas costs. SPPC also requested that $0.02857 per therm be added to the Balancing Account Adjustment (BAA) rate to amortize an approximate $3.9 million balance of deferred gas costs, which were accumulated during the accounting period. Combined with the simultaneous expiration of past BAA charges, the new BAA rate would be $.03869 per therm less than the current BAA rate. Overall, this request would result in a rate increase of approximately 5%.

The parties agreed to a stipulation, which recommended the PUCN approve the requested rates and the PUCN issued an order approving the rate increase on November 8, 2004.

For further detail of deferred energy cases see Note 3, Regulatory Actions of the Notes to Financial Statements

Sierra Pacific Power Company 2004 Integrated Resource Plan

SPPC filed its triennial resource plan with the PUCN on July 1, 2004. The significant provisions of the plan include efforts to minimize SPPC's reliance on a volatile energy market through a mix of owned generation, fuel diversity and purchased power. Consistent with this plan is a request for approval to construct a 500 MW combined cycle plant at SPPC's Tracy generation station to be in service in 2008 and to conduct the permitting and development activities necessary to construct an additional 250 MW coal-fired unit at Valmy to be placed in-service in the 2011 to 2015 time frame. SPPC will fill its remaining open position with purchased power from renewable energy providers and non-renewable sources.

Additionally SPPC sought PUCN approval on the following items:

- Designation of the combined cycle plant as a "critical facility" in accordance with the PUCN's regulations which allows for an enhanced return on equity on the designated "critical facility" over the life of the facility. The Tracy facility is a "critical facility" under the PUCN's recently amended resource planning regulations because it promotes price stability and reliability and reduces dependence on purchased power.
- Approval to upgrade the combustion systems at SPPC's Valmy generating station to comply with the emission standards of the "Clear Skies Initiative".
- Approval to conduct a study on the feasibility of additional coal-fired generation at SPPC's Valmy generation plant.
- Approval of the renewable energy promotion program through which SPPC will promote renewable energy development.
- Approval of SPPC's energy supply plan for the period from 2005 through 2007. The energy supply plan includes a recommendation for the issuance of a request for proposals for short and intermediate term power contracts to fill a significant portion of SPPC's capacity requirements during that period. The energy supply plan also includes a recommended gas hedging strategy for April 2005 through March 2006.
- Approval of the construction of a new 345 kV transmission line from SPPC's existing East Tracy 345 kV substation to a new 345 kV substation (Emma) located east of Virginia City.

SPPC and parties reached agreement on the issues and presented a stipulation to the PUCN on October 12, 2004. The stipulation calls for budget adjustments in the Demand Side Management programs and continued discussions to develop a new cost/benefit test for such programs. The stipulation authorizes SPPC to proceed with permitting activities for a 500 MW combined cycle power plant as requested and requires SPPC to file a Resource Plan Amendment to reaffirm the need for the 500 MW capacity addition before August 1, 2005. SPPC's request for a "critical facility" designation and the associated enhanced ROE was deferred for consideration during the amendment proceedings. On November 18, 2004, the PUCN issued an Order approving the stipulation. All other supply side proposals were approved as filed. In its Order, the PUCN approved and determined the power procurement element of the Energy Supply Plan to be prudent; however, no determination of prudency was made in regard to the fuel procurement plan and risk management strategy. Prudency with regard to fuel procurement and risk management will be determined in the appropriate deferred energy proceeding.

Sierra Pacific Power Company—Miscellaneous Amendments to its 2004 Integrated Resource Plan

SPPC has filed four amendments to its 2004 IRP. The first three amendments requested approval of a 20 year 7MW renewable energy contract, an 8MW power purchase agreement from Barrick's planned new generation plant (see "Large Customer Applications to Acquire Energy From New Supplies" below), and contracts to purchase renewable energy credits from existing renewable energy generators.

Nevada Power Company/Sierra Pacific Power Company Quality of Service Investigation

In compliance with the order issued in NPC's 2003 General Rate case, NPC and SPPC jointly filed with the PUCN, on July 1, 2004, their recommended quality of service and customer service measurements. In the filing, the Utilities outlined their proposed methodologies for measuring the quality of service and customer service measurements, pre- and post-merger. More specifically the companies identified the quality of service and customer service measurements to be used in a future rate case, proposed methodology for comparing pre-merger and post-merger performance, and proposed consequences and rewards for under- or over-performance in a future test year. The PUCN has noticed the filing and has set a procedural schedule. On March 2, 2005, the Intervener's in the case, the staff of the PUCN and the BCP, filed testimony regarding their proposed methodologies for measuring quality of service and customer service measurements. The Utilities have until April 18, 2005 to file rebuttal testimony, and a hearing has been scheduled to commence on May 16, 2005.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

OTHER NEVADA MATTERS

Large Customer Applications to Acquire Energy From New Supplies (AB661 Applications)

Barrick Application

In February 2004, Barrick Gold (Barrick), a large SPPC mining customer filed an AB661 application. Barrick intends to construct a generating facility to meet its electric power needs and will purchase transmission and distribution service from SPPC. Barrick, SPPC and other parties reached an agreement prior to hearings and it was presented to the PUCN on May 19, 2004. The PUCN issued an order approving the application as stipulated in the agreement on June 22, 2004. Following the PUCN approval, Barrick provided official notice of departure to SPPC on October 22, 2004; Barrick's departure will occur in November 2005.

Upon exiting, Barrick has agreed to pay a $10.8 million impact charge that will mitigate the impact of Barrick's departure from bundled electric service and insure no economic harm to remaining customers of SPPC. The impact charge will be reduced by $2.8 million to $7.9 million to reflect the 8 MW of capacity that will be provided to SPPC in a three- year purchase power agreement with deliveries beginning when Barrick's generation is operational. Barrick will also pay its share of Deferred Energy costs, estimated to be approximately $6 million at Barrick's departure date. These costs are the fuel and purchased power costs attributable to serving Barrick that will not have been collected as of Barrick's departure date. The departure of Barrick is not expected to have a material impact on the results of operations of SPPC.

Newmont Mining Transaction

The Newmont Mining Corporation and SPPC have developed terms and conditions under which Newmont's affiliate, Northern Nevada Energy Investment (NNEI), will construct a 203 MW coal fired generating plant, the output of which NNEI will sell to SPPC. SPPC will in turn sell part of the plant's output to Newmont to serve a portion of Newmont's mining loads under a new tariff and will retain the remainder to serve its other system customers. Newmont's peak load is forecasted to be 125 MW at the time its generation is expected to be operational in 2008. The Term Sheet provides that Newmont will remain a fully bundled customer of SPPC for at least 15 years after the plant achieves commercial operation.

SPPC and Newmont have submitted a number of related filings which were approved by the PUCN on February 23, 2005. The proposed transaction is anticipated to be a significant benefit to SPPC's remaining customers.

CALIFORNIA ELECTRIC MATTERS (SPPC)

Sierra Pacific Power Company 2004 Energy Cost Adjustment Clause

On May 1, 2004, SPPC filed its annual Energy Cost Adjustment Clause (ECAC) in California. The filing updated its estimated fuel and purchase power costs for its California customers and sought to recover or refund any deferred amounts projected through September 30, 2004. The filing requests $8.3 million or a 14.8% overall increase consisting of $3.9 million increase in the base rate and $4.4 million for the projected balance. Pre-hearing conferences were held on July 14 and August 4, 2004. On August 16, 2004, the CPUC Office of Ratepayer Advocates issued a report recommending the CPUC accept SPPC's ECAC proposal with a minor change to the rate design calculations. SPPC accepted the change and the resulting decrease to the request of $10,000. On October 4, 2004, the CPUC issued a draft order recommending approval of SPPC's adjusted ECAC proposal. No hearings were necessary and on November 19, 2004, the CPUC approved SPPC's adjusted request and the increase became effective December 1, 2004.

Rate Stabilization Plan

On June 29, 2001, SPPC filed with the CPUC a Rate Stabilization Plan, which included two phases. Phase One, which was also filed June 29, 2001, was an emergency electric rate increase of $10.2 million annually or 26%. If granted, the typical residential monthly electric bill for a customer using 650 kilowatt-hours would have increased from approximately $47.12 to $60.12. On July 17, 2002, the CPUC approved the requested 2-cent per kilowatt-hour surcharge, subject to refund and interest pending the outcome of Phase Two. The increase of $10 million or 26% is applicable to all customers except those eligible for low-income and medical-needs rates and went into effect July 18, 2002.

Phase Two of the Rate Stabilization Plan was filed with the CPUC on April 1, 2002, and included a general rate case and requests the CPUC to reinstate the Energy Cost Adjustment Clause, which would allow SPPC to file for annual rate adjustments to reflect its actual costs for wholesale energy supplies. This request was for an additional overall increase in revenues of 17.1%, or $8.9 million annually.

On January 8, 2004, the CPUC issued Decision No. 04-01-027, which approved a settlement agreement that included an increase of $3 million or 5.8%, adopted a rate design methodology and re-instituted the Energy Cost Adjustment (ECAC) mechanism. The rate increase was effective January 16, 2004.

FERC MATTERS

Sierra Pacific Power Company 2004 Transmission Rate Case

On October 1, 2004, the Utilities filed with the FERC revised rates for transmission service offered by SPPC under Docket No. ER05-14. The purpose of the filing was to update rates to reflect recent transmission additions and to improve rate design. The participants in the proceeding reached a settlement in principle of all issues on February 15, 2005. The parties will file a Settlement Agreement with the FERC and expect FERC to issue an Order approving settlement in the second quarter of 2005.

Nevada Power Company 2003 Transmission Rate Case

On September 11, 2003, the Utilities filed with the FERC revised rates for transmission service offered by NPC under Docket No. ER03-1328. The purpose of the filing is to update rates to reflect recent transmission additions and to improve rate design. On November 7, 2003, FERC accepted the revised tariff sheets, made rates effective on November 10, 2003, subject to refund, and established hearing procedures. The active participants in the proceeding reached a settlement in principle of all issues. The Certification of Uncontested Offer of Settlement was issued on June 14, 2004. The FERC issued an Order approving the uncontested settlement on July 8, 2004. Refunds were issued within thirty days as required by FERC.

Utilities' 2002 Open Access Transmission Tariff Filing and Rate Case

On September 27, 2002, the Utilities filed with the FERC a revised Open Access Transmission Tariff (OATT) designated as Docket No. ER02-2609-000. The purpose of the filing was to implement changes that are required to implement retail open access (AB 661) in Nevada. The Utilities requested the changes to become effective November 1, 2002, the date retail access was scheduled to commence in Nevada in accordance with provisions of AB 661, passed in the 2001 session of the Nevada Legislature.

On October 11, 2002, the Utilities filed with the FERC revised rates, terms, and conditions for ancillary services offered in the OATT designated Docket No. ER03-37-000. On November 25, 2002, FERC combined Docket No. ER02-2609-000 with Docket No. ER03-37-000 and suspended the rates in Docket No. ER03-37-000 for a nominal period and made them effective subject to refund on January 1, 2003. On July 1, 2003, FERC approved the offer of settlement that was filed on May 12, 2003. The Utilities issued refunds for amounts collected in excess of settlement rates and filed a report of such refunds at the FERC as instructed in the July 1 letter order.

Open Access Transmission Tariff Audit

On August 30, 2004, the FERC announced that it was commencing an audit to determine whether and how SPPC and NPC and their affiliates are complying with the Open Access Transmission Tariff, Market-Based Rate Tariff, and Codes of Conduct. The FERC's Division of Operational Audits of the Office of Market Oversight and Investigations is conducting the audit. The auditors have conducted on-site visits at both utilities and have issued requests for data.

California Wholesale Spot Market Refunds

NPC and SPPC are participants in a FERC proceeding wherein California parties have been authorized to recalculate, or mitigate, the prices they paid for wholesale spot market power between October 2, 2000 and June 20, 2001. Both of the Utilities made spot market sales that are eligible for mitigation, therefore the Utilities expect to pay refunds resulting from the recalculated energy prices. Parties have contested the FERC's decision to limit the timeframe for the recalculations and a recent Ninth Circuit court decision remanded a related issue to the FERC, therefore NPC and SPPC are not able to determine the eventual magnitude of refunds that may result from this FERC process.

NPC and SPPC are actively participating in this docket to ensure their interests are represented.

Nevada Power Company

Based on the FERC's orders to date, NPC believes the recalculated energy prices for NPC sales to the California Independent System Operator (CAISO) and the bankrupt California Power Exchange (CALPX) would result in a $13 million refund. The FERC has also allowed for energy sellers to provide cost justification in the event the recalculated energy prices fall below sellers' costs. Based on NPC's interpretation of the current FERC orders, NPC believes there should be a $4 million reduction to the estimated refunds resulting in a $9 million refund.

The CAISO and CALPX currently owe NPC approximately $19 million for power delivered during the same timeframe and NPC recorded a reserve against the $19 million receivable in 2001. The FERC has ordered CAISO and CALPX receivables to be netted against payables, therefore the estimated NPC refund does not require an additional liability to be recorded.

Parties have challenged a number of the FERC's decisions in the courts. NPC is not able to determine the magnitude of future refunds that may result from court actions.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

Sierra Pacific Power Company

Based on the FERC's orders to date, SPPC believes the recalculated energy prices for sales to the CAISO and CALPX during the October 2, 2000 to June 20, 2001 timeframe would result in a $4 million refund. A cost based justification applicable to SPPC has been discussed in the FERC orders, but the concepts have not been refined to a point where SPPC can determine if any reduction to the refund is likely. SPPC has recommended a process that would reduce SPPC's refund liability.

The CAISO and CALPX currently owe SPPC approximately $1 million for power delivered during the same timeframe and SPPC recorded a reserve against the $1 million receivable in 2001. In 2004, SPPC recorded an additional $3 million liability for this item.

Parties have challenged a number of the FERC's decisions in the courts. SPPC is not able to determine the magnitude of future refunds that may result from court actions.

RECENT PRONOUNCEMENTS

In December 2003, the FASB issued Interpretation No. 46, as revised December 2003 "Consolidation of Variable Interest Entities," (FIN 46 (R)), which elaborates on Accounting Research Bulletin No. 51, "Consolidated Financial Statements." Among other requirements, FIN 46 (R) provides that a variable interest entity be consolidated by the enterprise that is the primary beneficiary of the variable interest entity. As of December 31, 2003, SPR, NPC, and SPPC adopted FIN 46 (R) for special purpose entities. As of March 31, 2004, SPR, NPC and SPPC adopted FIN 46 (R) for all variable interest entities. To identify potential variable interests, management reviewed long term purchase power contracts, including contracts with qualifying facilities (QFs), jointly owned facilities and partnerships that are not consolidated. The Utilities identified seven QFs with long-term purchase power contracts that are variable interests. However, the Utilities are not required at this time to consolidate these QFs under the scope exception provided for in FIN 46 (R) due to the inability to obtain information necessary to (1) determine whether the entity is a variable interest entity, (2) determine whether the enterprise is the variable interest entity's primary beneficiary, or (3) perform the accounting required to consolidate the variable interest entity for which it is determined to be the primary beneficiary. The Utilities have requested financial information from these QFs but have not been successful in obtaining the information. The Utilities' maximum exposure to loss is limited to the cost of replacing these purchase power contracts if the QFs are unable to deliver power. However, the Utilities believe their exposure is mitigated as they would likely recover these costs through their deferred energy accounting mechanism. The Utilities have not identified any other significant variable interests that require consolidation as of December 31, 2004.

FSP FAS 106-2

The Financial Accounting Standards Board (FASB) issued a Staff Position (FSP) to modify Statement of Financial Accounting Standards 106 (FSP FAS 106-2) in May 2004 to provide guidance on accounting for the effects of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act), signed into law on December 8, 2003. This FSP supersedes FSP FAS 106-1, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003, under which elected to defer implementation due to the lack of definitive guidelines from the FASB and the Department of Health and Human Services. SPR has concluded that its prescription drug plan would qualify for the federal subsidy under this Act.

FSP FAS 106-2 applies only to sponsors of single-employer defined benefit postretirement health care plans for which (1) the employer has concluded that prescription drug benefits available under the plan to some or all participants, for some or all future years, are "actuarially equivalent" to Medicare Part D and thus qualify for the subsidy provided by the Act, and (2) the expected subsidy will offset or reduce the employer's share of the cost of the underlying postretirement prescription drug coverage on which the subsidy is based. The FSP provides guidance on measuring the accumulated postretirement benefit obligation (APBO) and net periodic postretirement benefit cost, and the effects of the Act on APBO. In addition, the FSP addresses accounting for plan amendments, and requires certain disclosures about the Act and its effects on financial statements. The effect of the subsidy on the APBO for benefits attributable to past service will be accounted for as an actuarial experience gain pursuant to Statement 106. Because the subsidy affects the employer's share of its plan's costs, the subsidy is included in measuring the costs of benefits attributable to current service. Therefore, the subsidy reduces service cost when it is recognized as a component of net periodic postretirement benefit cost. The FSP allows for either prospective recognition from the date of adoption or retroactive recognition by restating prior quarters for the effect of the change. The latter treatment will allow for the recognition of the cumulative effect of change on prior year's financial statements, if material, but will not require statements to be reissued. The FSP is effective for the first interim or annual period beginning after June 15, 2004.

Final guidelines were issued by the Department of Health and Human Services on July 26, 2004, and SPR completed its evaluation of the impact of this Act on its postretirement benefit expense. SPR elected to adopt FSP FAS 106-2 prospectively, valuing the annual benefit of the subsidy as of April 1, 2004, and recognizing one half of this amount in the third and fourth quarters. (The April 1 valuation was required for companies using an annual measurement date of September 30 for pension plans, and electing to adopt FSP FAS 106-2 prospectively.) The valuation resulted in an annual reduction to other postretirement benefit costs of $0.8 million. Accordingly, SPR recognized $0.2 million in each of the third and fourth quarters of 2004. Also refer to Note 12, Retirement Plan and Postretirement Benefits of the Notes to Financial Statements for further discussion.

FSP FAS 129-1

In April 2004, the FASB issued FSP FAS 129-1, Disclosure Requirements under FASB Statement No. 129, Disclosure of Information about Capital Structure, relating to Contingently Convertible Securities to provide disclosure guidance for contingently convertible securities, including those instruments with contingent conversion requirements that have not been met and otherwise are not required to be included in the computation of diluted earnings per share. In order to comply with the requirements of FAS 129, the significant terms of the conversion features of the contingently convertible security should be disclosed including: (i) events or changes in circumstances that would cause the contingency to be met and any significant features necessary to understand the conversion rights and the timing of the rights, (ii) the conversion price and the number of shares into which the security is potentially convertible, (iii) events or changes in circumstances, if any, that could adjust or change the contingency, conversion price, or number of shares, including significant terms of those changes and (iv) the manner of settlement upon conversion and any alternative methods. SPR has adopted and implemented the disclosure requirements of FSP FAS 129-1. See Note 7, Long-Term Debt of the Notes to Financial Statement for further discussion.

EITF 03-6

The Emerging Issues Task Force (EITF) of the FASB nullified the guidelines given in EITF Topic D-95 with regards to the effect of participating convertible securities on the computation of basic earnings per share by issuing EITF 03-6, Participating Securities and the Two-Class Method under FASB Statement No. 128. Under Topic D-95 (see Note 17, Earnings Per Share of the Notes to Financial Statements), companies were required to use either the "two-class" or the "if-converted" method to account for potential dilution due to participating convertible securities that could be converted into common stock, if the effect was dilutive. This was to be used in the calculation of basic and diluted earnings per share.

Accordingly, SPR included the dilutive effects of its convertible 7.25% notes due 2010, or Convertible Notes, in its financial statements for the three months ended September 30, 2003 using the "if-converted" method. The impact of conversion was deemed to be anti-dilutive for all other periods in 2003 and 2004 when Topic D-95 was effective. EITF 03-6 now requires using the "two-class" method to record the effect of participating securities in the computation of basic earnings per share, and the "if-converted" method in the computation of diluted earnings per share.

The FASB ratified the consensus reached by the EITF on Issue 03-6 on March 31, 2004, and made it effective for fiscal periods commencing after this date. SPR has adopted the "two-class" method to show the potential dilutive effect of its Convertible Notes in the computation of basic earnings per share for all financial statements issued after March 31, 2004.

FAS 123 (R)

The FASB issued Statement of Financial Accounting Standard No. 123 (revised 2004), "Share-Based Payment", (SFAS 123(R) in December 2004, which requires all public companies to measure and recognize the fair value of equity instrument awards granted to employees. SFAS 123(R) is effective for periods beginning after June 15, 2005 for most companies, and amends the current accounting standard, SFAS 123, which has been in effect since 1995. The new standard is similar to SFAS 123, but will now require recognition of costs using fair value accounting for companies that opted to follow the guidance of APB 25 to account for stock compensation costs. SFAS 123(R) does not require companies to use a specific valuation methodology, but it does indicate a clear preference for the use of complex "lattice models" rather than a traditional Black-Scholes model. SPR will use the fair-value method to recognize stock compensation costs commencing in the third quarter of 2005, using the modified prospective method of adoption. New awards and awards modified, repurchased or cancelled after July 1, 2005 will be accounted for under the new standard. Awards granted prior to this date for which the required service is yet to be rendered will also receive similar treatment. Amounts that were previously shown in footnote disclosure by SPR will now be recognized in the income statement.

See Note 1, Summary of Significant Accounting Policies of the Notes to Financial Statements for further discussion of accounting policies and recent pronouncements.

Commodity Price Risk

Commodity price increases due to changes in market conditions are recovered through the deferred energy accounting mechanism. Although the Utilities actively manage energy commodity (electric, natural gas, coal, and oil) price risk through their procurement strategies, the ability to recover commodity price changes through future rates substantially mitigates commodity price risk. However, the Utilities are subject to cash flow risk due to changes in the value of their open positions and are subject to regulatory risk because the PUCN may disallow recovery for any costs that it considers imprudently incurred. The Utilities mitigate both risk associated with its open positions and regulatory risk through prudent energy supply practices which include the use of long-term fuel supply agreements, long-term purchase power agreements and derivative instruments such as forwards, options and swaps to meet the anticipated fuel and power requirements. See Energy Supply in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, for a discussion of the Utilities' purchased power procurement strategies and Note 14, Commitments and Contingencies, Regulatory Contingencies, of the Notes to Financial Statements for a discussion of amounts subject to regulatory risk.

Credit Risk

The Utilities monitor and manage credit risk with their trading counterparties. Credit risk is defined as the possibility that a counterparty to one or more contracts will be unable or unwilling to fulfill its financial or physical obligations to the Utilities because of the counterparty's financial condition. The Utilities' credit risk associated with trading counterparties was approximately $3,565,328 as of December 31, 2004. In the event that the trading counterparties are unable to deliver under their contracts, it may be necessary for the Utilities to purchase alternative energy at a higher market price.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (continued)

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Interest Rate Risk

SPR, NPC, and SPPC have evaluated their risk related to financial instruments whose values are subject to market sensitivity. Such instruments are fixed and variable rate debt and preferred trust securities obligations. Fair market value is determined using quoted market price for the same or similar issues or on the current rates offered for debt of the same remaining maturities (dollars in thousands).

	December 31, 2004							
Expected Maturity Date	2005	2006	2007	2008	2009	Thereafter	Total	Fair Value
LONG-TERM DEBT								
SPR								
Fixed rate	$ —	$ —	$240,218	$ —	$ —	$ 635,000	$ 875,218	$1,200,538
Average interest rate			7.93%			7.98%	7.96%	
NPC								
Fixed rate	$ 15	$ 15	$ 17	$ 13	$250,000	$1,863,548	$2,113,608	$2,255,798
Average interest rate	8.17%	8.17%	8.17%	8.17%	10.88%	7.99%	8.62%	
Variable rate					$115,000		$ 115,000	$ 115,000
Average interest rate					1.74%		1.74%	
SPPC								
Fixed rate	$ 2,400	$ 52,400	$ 2,400	$322,400	$ 600	$ 617,250	$ 997,450	$1,028,328
Average interest rate	6.10%	6.71%	6.10%	7.99%	6.10%	6.52%	6.59%	
TOTAL DEBT	$ 2,415	$ 52,415	$242,635	$322,413	$365,600	$3,115,798	$4,101,276	$4,599,664

	December 31, 2003							
Expected Maturity Date	2005	2006	2007	2008	2009	Thereafter	Total	Fair Value
LONG-TERM DEBT								
SPR								
Fixed rate	$ 19,666	$300,000	$ —	$240,218	$ —	$ 300,000	$ 859,884	$1,062,997
Average interest rate	8.00%	8.75%		7.93%		7.25%	7.98%	
NPC								
Fixed rate	$130,013	$ 15	$ 15	$ 17	$ 13	$1,733,548	$1,863,621	$1,913,704
Average interest rate	6.20%	8.17%	8.17%	8.17%	8.17%	8.10%	7.83%	
Variable rate						$ 115,000	$ 115,000	$ 115,000
Average interest rate						1.74%	1.74%	
SPPC								
Fixed rate	$ 83,400	$100,400	$ 52,400	$ 2,400	$322,400	$ 437,850	$ 998,850	$1,020,327
Average interest rate	5.82%	10.39%	6.71%	6.10%	7.99%	7.63%	7.31%	
TOTAL DEBT	$233,079	$400,415	$ 52,415	$242,635	$322,413	$2,586,398	$3,837,355	$4,112,028

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Sierra Pacific Resources is responsible for establishing and maintaining adequate internal control over financial reporting. Sierra Pacific Resources' internal control system was designed to provide reasonable assurance to the company's management and board of directors regarding the preparation and fair presentation of published financial statements.

Although Sierra Pacific Resources is firmly committed to effective internal controls over financial reporting, internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Sierra Pacific Resources' management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2004. In making this assessment, Sierra Pacific Resources used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control—Integrated Framework.* Based on our assessment we believe that, as of December 31, 2004, the Company's internal control over financial reporting is effective based on those criteria.

Sierra Pacific Resources' independent auditors have issued an audit report on our assessment of the Company's internal control over financial reporting.

March 15, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Sierra Pacific Resources
Reno, Nevada

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that Sierra Pacific Resources and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2004, based on 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 and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2004, 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*. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission*.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2004 of the Company and our report dated March 15, 2005 expressed an unqualified opinion, and included explanatory paragraphs related to the adoption of Statement of Financial Accounting Standards No. 142 and Emerging Issues Task Force No. 03-6.

Deloitte & Touche LLP

Reno, Nevada
March 15, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
Sierra Pacific Resources
Reno, Nevada

We have audited the accompanying consolidated balance sheets and statements of capitalization of Sierra Pacific Resources and subsidiaries as of December 31, 2004 and 2003, and the related consolidated statements of operations, comprehensive income (loss), common shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2004. 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 the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. 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 Sierra Pacific Resources and subsidiaries as of December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 17, to the consolidated financial statements, during 2004 the Company changed its method used to calculate earning per share to conform to the Emerging Issues Task Force Issue No. 03-6 "Participating Securities and the Two-Class Method under FASB Statement No. 128."

As discussed in Note 1, to the consolidated financial statements, during 2002 the Company changed its method of accounting for goodwill to conform to Statement of Financial Accounting Standard No. 142, "Accounting for Goodwill."

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2004, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 15, 2005 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Deloitte & Touche LLP

Reno, Nevada
March 15, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Nevada Power Company
Reno, Nevada

We have audited the accompanying consolidated balance sheets and statements of capitalization of Nevada Power Company and subsidiaries as of December 31, 2004 and 2003, and the related consolidated statements of operations, comprehensive income (loss), common shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2004. 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 the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also 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, 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 Nevada Power Company and subsidiaries as of December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Reno, Nevada
March 15, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Sierra Pacific Power Company
Reno, Nevada

We have audited the accompanying consolidated balance sheets and statements of capitalization of Sierra Pacific Power Company and subsidiaries as of December 31, 2004 and 2003, and the related consolidated statements of operations, comprehensive income (loss), common shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2004. 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 the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also 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, 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 Sierra Pacific Power Company and subsidiaries as of December 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Reno, Nevada
March 15, 2005

CONSOLIDATED BALANCE SHEETS—SIERRA PACIFIC RESOURCES

December 31,	**2004**	2003
(dollars in thousands)		
ASSETS		
Utility Plant at Original Cost:		
Plant-in-service	**$6,604,449**	$6,353,399
Less accumulated provision for depreciation	**2,083,434**	1,953,271
	4,521,015	4,400,128
Construction work-in-progress	**405,911**	242,522
	4,926,926	4,642,650
Investments and other property, net	**64,596**	73,130
Current Assets:		
Cash and cash equivalents	**266,328**	181,757
Restricted cash and investments (Note 1)	**88,452**	54,705
Accounts receivable less allowance for uncollectible accounts: 2004—$36,197; 2003—$44,917	**320,676**	301,322
Deferred energy costs—electric (Note 1)	**148,008**	295,677
Deferred energy costs—gas (Note 1)	**3,106**	1,358
Materials, supplies, and fuel, at average cost	**76,193**	79,525
Risk management assets (Note 10)	**14,585**	22,099
Deposits and prepayments for energy	**54,767**	63,847
Other	**37,494**	33,016
	1,009,609	1,033,306
Deferred Charges and Other Assets:		
Goodwill (Note 19)	**22,877**	309,971
Deferred energy costs—electric	**526,159**	497,905
Deferred energy costs—gas	**2,491**	—
Regulatory tax asset	**279,766**	155,547
Other regulatory assets (Note 1)	**487,762**	142,507
Risk management regulatory assets—net (Note 10)	**6,673**	14,283
Unamortized debt issuance expense	**67,204**	50,842
Other	**114,297**	103,545
	1,507,229	1,274,600
Assets of Discontinued Operations (Note 18)	**20,107**	40,072
TOTAL ASSETS	**$7,528,467**	$7,063,758

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

(continued)

CONSOLIDATED BALANCE SHEETS—SIERRA PACIFIC RESOURCES (continued)

December 31,	**2004**	2003
(dollars in thousands)		
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Common shareholders' equity	**$1,498,616**	$1,435,394
Preferred stock	**50,000**	50,000
Long-term debt	**4,081,281**	3,579,674
	5,629,897	5,065,068
Current Liabilities:		
Short-term borrowings	**—**	25,000
Current maturities of long-term debt	**8,491**	218,970
Accounts payable	**179,559**	165,936
Accrued interest	**69,246**	59,592
Dividends declared	**1,046**	968
Accrued salaries and benefits	**28,547**	24,444
Deferred income taxes	**54,501**	106,478
Risk management liabilities (Note 10)	**9,902**	16,540
Accrued taxes	**5,470**	8,077
Contract termination liabilities (Note 14)	**303,460**	338,704
Other current liabilities	**38,702**	29,088
	698,924	993,797
Commitments and Contingencies (Note 14)		
Deferred Credits and Other Liabilities:		
Deferred income taxes	**512,760**	298,457
Deferred investment tax credit	**42,064**	45,329
Regulatory tax liability	**40,575**	41,877
Customer advances for construction	**142,703**	126,506
Accrued retirement benefits	**67,907**	112,075
Contract termination liabilities (Note 14)	**36,753**	45,766
Regulatory liabilities (Note 1)	**257,495**	218,158
Other	**89,189**	80,859
	1,189,446	969,027
Liabilities of Discontinued Operations (Note 18)	**10,200**	35,866
TOTAL CAPITALIZATION AND LIABILITIES	**$7,528,467**	$7,063,758

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

CONSOLIDATED STATEMENTS OF OPERATIONS— SIERRA PACIFIC RESOURCES

Year ended December 31,	2004	2003	2002
(dollars in thousands, except per share amounts)			
OPERATING REVENUES:			
Electric	**$ 2,666,000**	$ 2,624,426	$ 2,832,285
Gas	**153,752**	161,586	149,783
Other	**4,087**	1,531	2,536
	2,823,839	2,787,543	2,984,604
OPERATING EXPENSES:			
Operation:			
Purchased power	**1,069,302**	1,145,219	1,786,823
Fuel for power generation	**459,478**	480,537	453,436
Gas purchased for resale	**121,526**	111,675	91,961
Deferred energy costs disallowed	**1,586**	90,964	491,081
Deferral of energy costs—electric—net	**143,033**	97,893	(233,814)
Deferral of energy costs—gas—net	**(4,136)**	16,155	24,785
Impairment of goodwill	**11,695**	—	—
Other	**328,685**	324,608	279,896
Maintenance	**78,907**	69,636	64,440
Depreciation and amortization	**205,647**	191,259	174,200
Taxes:			
Income taxes (benefits)	**24,443**	(57,008)	(165,249)
Other than income	**44,888**	45,141	44,554
	2,485,054	2,516,079	3,012,113
OPERATING INCOME (LOSS)	**338,785**	271,464	(27,509)
OTHER INCOME (EXPENSE):			
Allowance for other funds used during construction	**5,948**	5,765	(36)
Interest accrued on deferred energy	**25,332**	28,054	23,058
Disallowed merger costs	**(5,890)**	—	—
Disallowed plant costs	**(47,092)**	—	—
Other income	**34,937**	29,948	10,988
Other expense	**(13,770)**	(14,243)	(18,365)
Income taxes (benefits)	**3,812**	(12,801)	(4,058)
Unrealized (loss) on derivative instrument	**—**	(46,065)	—
	3,277	(9,342)	11,587
Total Income (Loss) Before Interest Charges	**342,062**	262,122	(15,922)

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

(continued)

CONSOLIDATED STATEMENTS OF OPERATIONS— SIERRA PACIFIC RESOURCES (continued)

Year ended December 31,	2004	2003	2002
(dollars in thousands, except per share amounts)			
INTEREST CHARGES:			
Long-term debt	$ 312,399	$ 293,482	$ 248,852
Interest on terminated contracts (Note 14)	(35,170)	48,332	5,564
Other	37,785	30,444	29,911
Allowance for borrowed funds used during construction	(8,587)	(5,976)	(5,270)
	306,427	366,282	279,057
INCOME (LOSS) FROM CONTINUING OPERATIONS	35,635	(104,160)	(294,979)
DISCONTINUED OPERATIONS:			
Loss from discontinued operations (net of income taxes (benefits) of $(1,704), $(17,036), and $(3,249) respectively)	(3,164)	(32,469)	(7,076)
CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE, net of tax (Note 1)	—	—	(1,566)
NET INCOME (LOSS)	32,471	(136,629)	(303,621)
Preferred stock dividend requirements of subsidiary	3,900	3,900	3,900
EARNINGS (DEFICIT) APPLICABLE TO COMMON STOCK	$ 28,571	$ (140,529)	$ (307,521)
Amount per share—(Note 17)			
Income (loss) from continuing operations—basic	$ 0.19	$ (0.90)	$ (2.89)
Earnings (deficit) applicable to common stock—basic	$ 0.16	$ (1.21)	$ (3.01)
Income (loss) from continuing operations—diluted	$ 0.19	$ (0.90)	$ (2.89)
Earnings (deficit) applicable to common stock—diluted	$ 0.16	$ (1.21)	$ (3.01)
Weighted Average Shares of Common Stock Outstanding—Basic	183,080,475	115,774,810	102,126,079
Weighted Average Shares of Common Stock Outstanding—Diluted	183,400,303	115,774,810	102,126,079

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)— SIERRA PACIFIC RESOURCES

Year ended December 31,	2004	2003	2002
(dollars in thousands)			
NET INCOME (LOSS)	$32,471	$(136,629)	$(303,621)
OTHER COMPREHENSIVE INCOME (LOSS)			
Adoption of SFAS No. 133—Accounting for Derivative Instruments and Hedging Activities:			
Change in market value of risk management assets and liabilities as of December 31 (net of taxes of $(950), $(884), and $(3,083) in 2004, 2003, and 2002, respectively)	1,763	1,642	5,726
Minimum pension liability adjustment (net of taxes of $(15,486), $(8,350), and $24,904 in 2004, 2003, and 2002, respectively)	29,404	15,508	(46,251)
OTHER COMPREHENSIVE INCOME (LOSS)	31,167	17,150	(40,525)
COMPREHENSIVE INCOME (LOSS)	$63,638	$(119,479)	$(344,146)

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

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY— SIERRA PACIFIC RESOURCES

December 31,	**2004**	2003	2002
(dollars in thousands)			
COMMON STOCK:			
Balance at Beginning of Year	**$ 117,236**	$ 102,177	$ 102,111
Stock issuance/exchange, CSIP, DRP, ESPP, and other	**233**	15,059	66
Balance at end of year	**117,469**	117,236	102,177
OTHER PAID-IN CAPITAL:			
Balance at Beginning of Year	**1,815,202**	1,599,024	1,598,634
Premium on issuance/exchange of common stock	**563**	99,192	—
Common stock issuance costs	**—**	(1,184)	—
Revaluation of investment	**1,690**	—	—
Value of derivative transferred to equity	**—**	118,143	—
CSIP, DRP, ESPP, and other	**998**	27	390
Balance at End of Year	**1,818,453**	1,815,202	1,599,024
RETAINED EARNINGS (DEFICIT):			
Balance (Deficit) at Beginning of Year	**(466,683)**	(326,524)	1,577
Income (loss) from continuing operations before preferred dividends	**35,635**	(104,160)	(294,979)
Loss from discontinued operations, net of taxes	**(3,164)**	(32,469)	(7,076)
Cumulative effect of change in accounting principle, net of tax	**—**	—	(1,566)
Preferred stock dividends declared	**(3,900)**	(3,900)	(3,900)
Common stock dividends declared, net of adjustments	**—**	370	(20,580)
Deficit at End of Year	**(438,112)**	(466,683)	(326,524)
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):			
Balance at Beginning of Year	**(30,361)**	(47,511)	(6,986)
Adoption of SFAS No. 133—Accounting for Derivative Instruments and Hedging Activities			
Change in market value of risk management assets and liabilities as of December 31 (net of taxes of $(950), $(884), and $(3,083) in 2004, 2003, and 2002, respectively)	**1,763**	1,642	5,726
Minimum pension liability adjustment (net of taxes of $(15,486), $(8,350), and $24,904 in 2004, 2003, and 2002, respectively)	**29,404**	15,508	(46,251)
Balance at End of Year	**806**	(30,361)	(47,511)
TOTAL COMMON SHAREHOLDERS' EQUITY AT END OF YEAR	**$1,498,616**	$1,435,394	$1,327,166

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

CONSOLIDATED STATEMENTS OF CASH FLOWS—SIERRA PACIFIC RESOURCES

Year ended December 31,	2004	2003	2002
(dollars in thousands)			
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income (Loss)	$ 32,471	$(136,629)	$(303,621)
Non-cash items included in net income (loss):			
Depreciation and amortization	205,647	191,259	174,200
Deferred taxes and deferred investment tax credit	33,690	(50,724)	(169,714)
AFUDC and capitalized interest	(14,536)	(11,741)	(5,234)
Amortization of deferred energy costs—electric	265,418	250,134	176,718
Amortization of deferred energy costs—gas	3,242	13,095	13,231
Deferred energy costs disallowed	1,586	90,964	493,053
Goodwill impairment	11,695	—	
Early retirement and severance amortization	—	2,786	2,706
Unrealized loss on derivative instrument	—	46,065	—
Impairment of assets of subsidiary	—	32,911	—
Loss on disposal of discontinued operations	2,346	9,555	—
Plant costs disallowed	47,092	—	—
Other non-cash	(27,353)	(7,131)	10,341
Changes in certain assets and liabilities:			
Accounts receivable	(19,354)	57,271	30,560
Deferral of energy costs—electric	(147,589)	(179,826)	(434,279)
Deferral of energy costs—gas	(7,480)	2,592	10,270
Materials, supplies, and fuel	3,331	6,277	5,317
Other current assets	4,601	(49,142)	(33,959)
Accounts payable	13,623	(66,097)	(23,707)
Income tax receivable	—	—	185,011
Escrow payment for terminating suppliers	(61,129)	—	—
Other current liabilities	20,609	358,213	16,413
Change in net assets of discontinued operations	(8,048)	(11,727)	667
Other assets	21,292	47,348	(13,764)
Other liabilities	(49,113)	(334,889)	320,253
Net Cash provided by Operating Activities	332,041	260,564	454,462
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to utility plant	(614,411)	(379,319)	(404,330)
AFUDC and other charges to utility plant	14,536	11,741	5,234
Customer advances for construction	16,197	10,475	7,852
Contributions in aid of construction	26,457	23,605	43,247
Net cash used for utility plant	(557,221)	(333,498)	(347,997)
Investments in subsidiaries and other property—net	16,574	(8,439)	(4,520)
Net Cash used in Investing Activities	(540,647)	(341,937)	(352,517)

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

(continued)

CONSOLIDATED STATEMENTS OF CASH FLOWS— SIERRA PACIFIC RESOURCES (continued)

Year ended December 31,	**2004**	2003	2002
(dollars in thousands)			
CASH FLOWS FROM FINANCING ACTIVITIES:			
Increase (decrease) in short-term borrowings	**$ (25,000)**	$ 25,000	$(177,000)
Change in restricted cash and investments	**27,382**	(41,000)	(13,705)
Proceeds from issuance of long-term debt	**965,000**	650,000	350,000
Retirement of long-term debt	**(673,872)**	(558,760)	(143,584)
Sale of common stock, net of issuance cost	**3,488**	(756)	460
Dividends paid	**(3,821)**	(3,524)	(24,485)
Net Cash provided by Financing Activities	**293,177**	70,960	(8,314)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**84,571**	(10,413)	93,631
Beginning Balance in Cash and Cash Equivalents	**181,757**	192,170	98,539
Ending Balance in Cash and Cash Equivalents	**$ 266,328**	$ 181,757	$ 192,170
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION:			
Cash paid (received) during period for:			
Interest	**$ 339,718**	$ 307,870	$ 257,462
Income taxes	**$ —**	$ (1,521)	$(185,011)
NON-CASH ACTIVITIES:			
Exchange of Floating Rate Notes for SPR Common Stock	**$ —**	$ 8,750	$ —
Exchange of Premium Income Equity Securities for SPR Common Stock	**$ —**	$ 104,782	$ —

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

CONSOLIDATED STATEMENTS OF CAPITALIZATION— SIERRA PACIFIC RESOURCES

December 31,	**2004**	2003
(dollars in thousands)		
COMMON SHAREHOLDERS' EQUITY:		
Common stock, $1.00 par value, authorized 250 million; issued and outstanding 2004:117,469,000 shares; issued and outstanding 2003:117,236,000 shares	**$ 117,469**	$ 117,236
Other paid-in capital	**1,818,453**	1,815,202
Retained deficit	**(438,112)**	(466,683)
Accumulated other comprehensive income (loss)	**806**	(30,361)
Total Common Shareholders' Equity	**1,498,616**	1,435,394
PREFERRED STOCK OF SUBSIDIARIES:		
Not subject to mandatory redemption; 2,000,000 shares outstanding; $25 stated value SPPC Class A Series 1; $ 1.95 dividend	**50,000**	50,000
LONG-TERM DEBT:		
SECURED DEBT		
First Mortgage Bonds		
8.50% NPC Series Z due 2023	**35,000**	35,000
Debt Secured by First Mortgage Bonds		
Revenue Bonds		
Nevada Power Company		
6.60% NPC Series 1992B due 2019	**39,500**	39,500
6.70% NPC Series 1992A due 2022	**105,000**	105,000
7.20% NPC Series 1992C due 2022	**78,000**	78,000
Sierra Pacific Power Company		
6.35% SPPC Series 1992B due 2012	**1,000**	1,000
6.55% SPPC Series 1987 due 2013	**39,500**	39,500
6.30% SPPC Series 1987 due 2014	**45,000**	45,000
6.65% SPPC Series 1987 due 2017	**92,500**	92,500
6.55% SPPC Series 1990 due 2020	**20,000**	20,000
6.30% SPPC Series 1992A due 2022	**10,250**	10,250
5.90% SPPC Series 1993A due 2023	**9,800**	9,800
5.90% SPPC Series 1993B due 2023	**30,000**	30,000
6.70% SPPC Series 1992 due 2032	**21,200**	21,200
Medium Term Notes		
Sierra Pacific Power Company		
6.62% to 6.83% SPPC Series C due 2006	**50,000**	50,000
6.95% to 8.61% SPPC Series A due 2022	**110,000**	110,000
7.10% to 7.14% SPPC Series B due 2023	**58,000**	58,000
Subtotal	**744,750**	744,750
General and Refunding Mortgage Securities		
Nevada Power Company		
6.200% NPC Series 1995B due 2004	**—**	130,000
10.88% NPC Series E due 2009	**250,000**	250,000
8.25% NPC Series A due 2011	**350,000**	350,000
6.50% NPC Series I due 2012	**130,000**	—
9.00% NPC Series G due 2013	**350,000**	350,000
5.875% NPC Series L due 2015	**250,000**	—
Sierra Pacific Power Company		
10.50% SPPC (Variable) Series C due 2005	**—**	99,000
8.00% SPPC Series A due 2008	**320,000**	320,000
6.25% SPPC Series H due 2012	**100,000**	—
Subtotal	**1,750,000**	1,499,000

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

(continued)

CONSOLIDATED STATEMENTS OF CAPITALIZATION— SIERRA PACIFIC RESOURCES (continued)

December 31,	2004	2003
(dollars in thousands)		
Debt Secured by General and Refunding Mortgage Securities		
NPC Series K due October 8, 2007 (Union Bank of California, N.A. Credit Agreement)		
SPPC Series L due October 22, 2007 (Union Bank of California, N.A. Credit Agreement)		
7.50% SPPC Series 2001 due 2036	**$ —**	$ 80,000
5.00% SPPC Series 2001 due 2036	**80,000**	—
Subtotal	**80,000**	80,000
UNSECURED DEBT		
Revenue Bonds		
Nevada Power Company		
5.30% NPC Series 1995D due 2011	**14,000**	14,000
5.35% NPC Series 1995E due 2022	**13,000**	13,000
5.45% NPC Series 1995D due 2023	**6,300**	6,300
5.50% NPC Series 1995C due 2030	**44,000**	44,000
5.60% NPC Series 1995A due 2030	**76,750**	76,750
5.90% NPC Series 1995B due 2030	**85,000**	85,000
5.80% NPC Series 1997B due 2032	**20,000**	20,000
5.90% NPC Series 1997A due 2032	**52,285**	52,285
6.38% NPC Series 1996 due 2036	**20,000**	20,000
Subtotal	**331,335**	331,335
Variable Rate Notes		
NPC PCRB Series 2000B due 2009	**15,000**	15,000
NPC IDRB Series 2000A due 2020	**100,000**	100,000
Subtotal	**115,000**	115,000
Other Notes		
Sierra Pacific Resources		
8.75% SPR Notes due 2005	**—**	300,000
7.93% SPR Senior Notes due 2007 (PIES)	**240,218**	240,218
7.25% SPR Convertible Notes due 2010	**242,078**	234,118
8.625% SPR Notes due 2014	**335,000**	—
Subtotal, excluding current portion	**817,296**	774,336
Unamortized bond premium and discount, net	**(16,604)**	(21,750)
Nevada Power Company		
8.2% Junior Subordinated Debentures of NPC, due 2037	**122,548**	122,548
7.75% Junior Subordinated Debentures of NPC, due 2038	**72,165**	72,165
Subtotal	**194,713**	194,713
Obligations under capital leases	**63,021**	68,587
Current maturities and sinking fund requirements	**(8,491)**	(238,636)
Other, excluding current portion	**10,261**	32,339
Total Long-Term Debt	**4,081,281**	3,579,674
TOTAL CAPITALIZATION	**$5,629,897**	$5,065,068

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

CONSOLIDATED BALANCE SHEETS—NEVADA POWER COMPANY

December 31,	**2004**	2003
(dollars in thousands)		
ASSETS		
Utility Plant at Original Cost:		
Plant-in-service	**$4,015,125**	$3,816,630
Less accumulated provision for depreciation	**1,112,335**	1,018,044
	2,902,790	2,798,586
Construction work-in-progress	**355,431**	109,148
	3,258,221	2,907,734
Investments and other property, net	**30,809**	36,312
Current Assets:		
Cash and cash equivalents	**243,323**	144,897
Restricted cash (Note 1)	**50,311**	2,600
Accounts receivable less allowance for uncollectible accounts: (2004-$30,901; 2003-$40,297)	**178,077**	167,296
Accounts receivable, affiliate companies	**—**	3,533
Deferred energy costs—electric (Note 1)	**126,074**	247,249
Materials, supplies, and fuel, at average cost	**44,858**	41,076
Risk management assets (Note 10)	**5,092**	11,702
Deposits and prepayments for energy	**23,091**	39,794
Other	**23,721**	21,540
	694,547	679,687
Deferred Charges and Other Assets:		
Deferred energy costs—electric (Note 1)	**375,120**	371,305
Regulatory tax asset	**167,221**	102,282
Other regulatory assets (Note 1)	**277,450**	60,721
Risk management regulatory assets—net (Note 10)	**3,555**	3,109
Unamortized debt issuance expense	**43,802**	34,052
Other	**32,815**	15,557
	899,963	587,026
TOTAL ASSETS	**$4,883,540**	$4,210,759

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

(continued)

CONSOLIDATED BALANCE SHEETS—NEVADA POWER COMPANY (continued)

December 31,	**2004**	2003
(dollars in thousands)		
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Common shareholders' equity	**$1,437,481**	$1,174,645
Long-term debt	**2,275,690**	1,899,709
	3,713,171	3,074,354
Current Liabilities:		
Current maturities of long-term debt	**6,091**	135,570
Accounts payable	**114,242**	107,812
Accounts payable, affiliated companies	**3,920**	—
Accrued interest	**40,677**	35,399
Dividends declared	**399**	—
Accrued salaries and benefits	**12,780**	10,315
Deferred income taxes	**36,981**	97,464
Risk management liabilities (Note 10)	**3,555**	5,266
Accrued taxes	**2,441**	4,934
Contract termination liabilities (Note 14)	**211,620**	235,729
Other current liabilities	**27,651**	22,397
	460,357	654,886
Commitments and Contingencies (Note 14)		
Deferred Credits and Other Liabilities:		
Deferred income taxes	**307,609**	124,914
Deferred investment tax credit	**18,642**	20,272
Regulatory tax liability	**16,506**	15,776
Customer advances for construction	**79,243**	71,176
Accrued retirement benefits	**21,025**	5,825
Contract termination liabilities (Note 14)	**34,847**	43,916
Regulatory liabilities (Note 1)	**171,330**	147,887
Other	**60,810**	51,753
	710,012	481,519
TOTAL CAPITALIZATION AND LIABILITIES	**$4,883,540**	$4,210,759

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

CONSOLIDATED STATEMENTS OF OPERATIONS— NEVADA POWER COMPANY

Year ended December 31,	**2004**	2003	2002
(dollars in thousands)			
OPERATING REVENUES:			
Electric	**$1,784,092**	$1,756,146	$1,901,034
OPERATING EXPENSES:			
Operation:			
Purchased power	**764,347**	781,014	1,241,783
Fuel for power generation	**235,404**	282,968	309,293
Deferred energy costs disallowed	**1,586**	45,964	434,123
Deferral of energy costs—net	**135,973**	95,911	(179,182)
Other	**183,736**	195,483	167,768
Maintenance	**57,030**	48,226	41,200
Depreciation and amortization	**118,841**	109,655	98,198
Taxes:			
Income taxes (benefits)	**45,135**	(12,734)	(133,411)
Other than income	**25,550**	25,926	25,265
	1,567,602	1,572,413	2,005,037
OPERATING INCOME (LOSS)	**216,490**	183,733	(104,003)
OTHER INCOME (EXPENSE):			
Allowance for other funds used during construction	**4,230**	2,845	(153)
Interest accrued on deferred energy	**20,199**	22,891	12,414
Disallowed merger costs	**(3,961)**	—	—
Other income	**22,844**	18,344	742
Other expense	**(6,665)**	(5,944)	(9,933)
Income taxes	**(11,437)**	(12,120)	(1,627)
	25,210	26,016	1,443
Total Income (Loss) Before Interest Charges	**241,700**	209,749	(102,560)
INTEREST CHARGES:			
Long-term debt	**152,764**	142,143	114,527
Interest on terminated contracts (Note 14)	**(24,171)**	33,879	4,101
Other	**14,533**	17,150	17,294
Allowance for borrowed funds used during construction	**(5,738)**	(2,700)	(3,412)
	137,388	190,472	132,510
NET INCOME (LOSS)	**$ 104,312**	$ 19,277	$ (235,070)

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)— NEVADA POWER COMPANY

Year ended December 31,	**2004**	2003	2002
(dollars in thousands)			
NET INCOME (LOSS)	**$104,312**	$19,277	$(235,070)
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX:			
Adoption of SFAS No. 133—Accounting for Derivative Instruments and Hedging Activities:			
Change in market value of risk management assets and liabilities as of December 31 (net of taxes of $(1,965), $(31), and $214 in 2004, 2003, and 2002, respectively)	**1,277**	59	(397)
Minimum pension liability adjustment (net of taxes of $(1,205), $(3,326), and $4,838 in 2004, 2003, and 2002, respectively)	**2,239**	6,178	(8,985)
OTHER COMPREHENSIVE INCOME (LOSS)	**3,516**	6,237	(9,382)
COMPREHENSIVE INCOME (LOSS)	**$107,828**	$25,514	$(244,452)

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

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY— NEVADA POWER COMPANY

December 31,	**2004**	2003	2002
(dollars in thousands)			
COMMON STOCK:			
Balance at Beginning of Year and End of Year	**$ 1**	$ 1	$ 1
OTHER PAID-IN CAPITAL:			
Balance at Beginning of Year	**1,377,106**	1,377,106	1,367,106
Transfer of regulatory asset (Note 19)	**197,998**	—	—
Revaluation of investment	**1,690**	—	10,000
Balance at End of Year	**1,576,794**	1,377,106	1,377,106
RETAINED EARNINGS (DEFICIT):			
Balance (Deficit) at Beginning of Year	**(199,837)**	(219,114)	25,956
Income (loss) for the year	**104,312**	19,277	(235,070)
Common stock dividends declared	**(45,373)**	—	(10,000)
Deficit at End of Year	**(140,898)**	(199,837)	(219,114)
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):			
Balance at Beginning of Year	**(2,625)**	(8,862)	520
Adoption of SFAS No. 133—Accounting for Derivative Instruments and Hedging Activities			
Change in market value of risk management assets and liabilities as of December 31 (net of taxes of $(688), $(31), and $214 in 2004, 2003, and 2002, respectively)	**1,277**	59	(397)
Minimum pension liability adjustment (net of taxes of $(1,205), $(3,326), and $4,838 in 2004, 2003, and 2002, respectively)	**2,239**	6,178	(8,985)
Balance at End of Year	**891**	(2,625)	(8,862)
TOTAL COMMON SHAREHOLDERS' EQUITY AT END OF YEAR	**$1,436,788**	$1,174,645	$1,149,131

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

CONSOLIDATED STATEMENTS OF CASH FLOWS—NEVADA POWER COMPANY

Year ended December 31,	**2004**	2003	2002
(dollars in thousands)			
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income (Loss)	**$ 104,312**	$ 19,277	$(235,070)
Non-cash items included in net income (loss):			
Depreciation and amortization	**118,841**	109,655	98,198
Deferred taxes and deferred investment tax credit	**57,066**	2,710	(131,076)
AFUDC	**(9,969)**	(5,545)	(3,259)
Amortization of deferred energy costs	**228,765**	204,610	146,554
Deferred energy costs disallowed	**1,586**	45,964	434,125
Other non-cash	**(44,149)**	(8,962)	(6,332)
Changes in certain assets and liabilities:			
Accounts receivable	**(7,247)**	31,761	8,487
Deferral of energy costs	**(112,992)**	(131,590)	(338,152)
Materials, supplies, and fuel	**(3,782)**	2,998	4,437
Other current assets	**14,522**	(29,732)	(24,841)
Accounts payable	**10,350**	(39,477)	(55,316)
Income tax receivable	**—**	—	102,904
Escrow payment for terminating suppliers	**(50,311)**	—	—
Other current liabilities	**10,504**	253,009	6,216
Other assets	**12,333**	21,303	—
Other liabilities	**12,811**	(208,051)	253,218
Net Cash provided by Operating Activities	**342,640**	267,930	260,093
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to utility plant	**(482,484)**	(229,368)	(296,966)
AFUDC and other charges to utility plant	**9,969**	5,545	3,259
Customer advances for construction	**8,067**	4,742	4,980
Contributions in aid of construction	**10,703**	12,168	35,800
Net cash used for utility plant	**(453,745)**	(206,913)	(252,927)
Investments in subsidiaries and other property—net	**5,404**	(15,512)	(2,239)
Net Cash used in Investing Activities	**(448,341)**	(222,425)	(255,166)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Increase (decrease) in short-term borrowings	**—**	—	(130,500)
Change in restricted cash and investments	**2,600**	1,250	(3,850)
Proceeds from issuance of long-term debt	**530,000**	350,000	250,000
Retirement of long-term debt	**(283,498)**	(346,867)	(34,073)
Investment by parent company	**—**	—	10,000
Dividends paid	**(44,975)**	—	(10,000)
Net Cash provided by Financing Activities	**204,127**	4,383	81,577
NET INCREASE IN CASH AND CASH EQUIVALENTS	**98,426**	49,888	86,504
Beginning Balance in Cash and Cash Equivalents	**144,897**	95,009	8,505
Ending Balance in Cash and Cash Equivalents	**$ 243,323**	$ 144,897	$ 95,009
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION:			
Cash paid (received) during period for:			
Interest	**$ 161,126**	$ 149,686	$ 109,679
Income taxes	**$ —**	$ —	$(102,904)
NON-CASH ACTIVITIES:			
Transfer of Regulatory Asset (Note 19)	**$ 197,998**	$ —	$ —

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

CONSOLIDATED STATEMENTS OF CAPITALIZATION— NEVADA POWER COMPANY

December 31,	2004	2003
(dollars in thousands)		
COMMON SHAREHOLDERS' EQUITY:		
Common stock, $1.00 par value, 1,000 shares authorized, issued and outstanding	**$ 1**	$ 1
Other paid-in capital	**1,576,794**	1,377,106
Retained deficit	**(140,898)**	(199,837)
Accumulated other comprehensive income (loss)	**891**	(2,625)
Total Common Shareholders' Equity	**1,436,788**	1,174,645
LONG-TERM DEBT:		
SECURED DEBT		
First Mortgage Bonds		
8.50% Series Z due 2023	**35,000**	35,000
Debt Secured by First Mortgage Bonds		
Revenue Bonds		
6.60% Series 1992B due 2019	**39,500**	39,500
6.70% Series 1992A due 2022	**105,000**	105,000
7.20% Series 1992C due 2022	**78,000**	78,000
Subtotal	**257,500**	257,500
General and Refunding Mortgage Securities		
6.20% Series 1995B due 2004	**—**	130,000
10.88% Series E due 2009	**250,000**	250,000
8.25% Series A due 2011	**350,000**	350,000
6.50% Series I due 2012	**130,000**	—
9.00% Series G due 2013	**350,000**	350,000
5.875% Series L due 2015	**250,000**	—
Subtotal	**1,330,000**	1,080,000
Debt Secured by General and Refunding Mortgage Securities		
Series K due October 22, 2007 (Union Bank of California, N.A. Credit Agreement)	**—**	—
UNSECURED DEBT		
Revenue Bonds		
5.30% Series 1995D due 2011	**14,000**	14,000
5.35% Series 1995E due 2022	**13,000**	13,000
5.45% Series 1995D due 2023	**6,300**	6,300
5.50% Series 1995C due 2030	**44,000**	44,000
5.60% Series 1995A due 2030	**76,750**	76,750
5.90% Series 1995B due 2030	**85,000**	85,000
5.80% Series 1997B due 2032	**20,000**	20,000
5.90% Series 1997A due 2032	**52,285**	52,285
6.38% Series 1996 due 2036	**20,000**	20,000
Subtotal	**331,335**	331,335
Variable Rate Notes		
PCRB Series 2000B due 2009	**15,000**	15,000
IDRB Series 2000A due 2020	**100,000**	100,000
Subtotal	**115,000**	115,000
Unamortized bond premium and discount, net	**(9,849)**	(11,929)
8.2% Junior Subordinated Debentures due 2037	**122,548**	122,548
7.75% Junior Subordinated Debentures due 2038	**72,165**	72,165
Subtotal	**194,713**	194,713
Obligations under capital leases	**63,021**	68,587
Current maturities and sinking fund requirements	**(6,091)**	(135,570)
Other, excluding current portion	**61**	73
Total Long-Term Debt	**2,275,690**	1,899,709
TOTAL CAPITALIZATION	**$3,712,478**	$3,074,354

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

CONSOLIDATED BALANCE SHEETS—
SIERRA PACIFIC POWER COMPANY

December 31,	2004	2003
(dollars in thousands)		
ASSETS		
Utility Plant at Original Cost:		
Plant-in-service	**$2,589,324**	$2,536,769
Less accumulated provision for depreciation	**971,099**	935,227
	1,618,225	1,601,542
Construction work-in-progress	**50,480**	133,374
	1,668,705	1,734,916
Investments and other property, net	**999**	916
CURRENT ASSETS:		
Cash and cash equivalents	**19,319**	20,859
Restricted cash (Note 1)	**16,464**	8,776
Accounts receivable less allowance for uncollectible accounts: (2004-$5,296; 2003-$4,620)	**142,359**	133,595
Accounts receivable, affiliated companies	**67,261**	56,349
Deferred energy costs—electric (Note 1)	**21,934**	48,428
Deferred energy costs—gas (Note 1)	**3,106**	1,358
Materials, supplies, and fuel, at average cost	**31,335**	38,449
Risk management assets (Note 10)	**9,493**	10,397
Deposits and prepayments for energy	**31,676**	24,053
Other	**9,728**	7,265
	352,675	349,529
Deferred Charges and Other Assets:		
Deferred energy costs—electric (Note 1)	**151,039**	126,600
Deferred energy costs—gas	**2,491**	—
Regulatory tax asset	**112,545**	53,265
Other regulatory assets (Note 1)	**210,312**	62,716
Risk management regulatory assets—net (Note 10)	**3,118**	11,174
Unamortized debt issuance expense	**13,564**	12,383
Other	**8,872**	10,970
	501,941	277,108
TOTAL ASSETS	**$2,524,320**	$2,362,469

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

(continued)

CONSOLIDATED BALANCE SHEETS— SIERRA PACIFIC·POWER COMPANY (continued)

December 31,	2004	2003
(dollars in thousands)		
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Common shareholders' equity	**$ 705,395**	$ 593,771
Preferred stock	**50,000**	50,000
Long-term debt	**994,309**	912,800
	1,749,704	1,556,571
Current Liabilities:		
Short-term borrowings	**—**	25,000
Current maturities of long-term debt	**2,400**	83,400
Accounts payable	**42,884**	40,731
Accrued interest	**9,604**	10,374
Dividends declared	**968**	968
Accrued salaries and benefits	**13,846**	11,775
Deferred income taxes	**17,138**	25,726
Risk management liabilities (Note 10)	**6,347**	11,274
Accrued taxes	**2,878**	3,009
Contract termination liabilities (Note 14)	**91,840**	102,975
Other current liabilities	**8,516**	4,120
	196,421	319,352
Commitments and Contingencies (Note 14)		
Deferred Credits and Other Liabilities:		
Deferred income taxes	**314,448**	231,274
Deferred investment tax credit	**23,422**	25,057
Regulatory tax liability	**24,069**	26,101
Customer advances for construction	**63,460**	55,330
Accrued retirement benefits	**41,558**	52,709
Contract termination liabilities (Note 14)	**1,906**	1,850
Regulatory liabilities (Note 1)	**86,165**	70,271
Other	**23,167**	23,954
	578,195	486,546
TOTAL CAPITALIZATION AND LIABILITIES	**$2,524,320**	$2,362,469

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

CONSOLIDATED STATEMENTS OF OPERATIONS— SIERRA PACIFIC POWER COMPANY

Year ended December 31,	**2004**	2003	2002
(dollars in thousands)			
OPERATING REVENUES:			
Electric	**$ 881,908**	$ 868,280	$ 931,251
Gas	**153,752**	161,586	149,783
	1,035,660	1,029,866	1,081,034
OPERATING EXPENSES:			
Operation:			
Purchased power	**304,955**	364,205	545,040
Fuel for power generation	**224,074**	197,569	144,143
Gas purchased for resale	**121,526**	111,675	91,961
Deferred energy costs disallowed	**—**	45,000	56,958
Deferral of energy costs—electric—net	**7,060**	1,982	(54,632)
Deferral of energy costs—gas—net	**(4,136)**	16,155	24,785
Other	**128,091**	116,390	106,122
Maintenance	**21,877**	21,410	23,240
Depreciation and amortization	**86,806**	81,514	76,373
Taxes:			
Income taxes (benefits)	**14,978**	(13,704)	(6,922)
Other than income	**19,184**	19,104	18,674
	924,415	961,300	1,025,742
OPERATING INCOME	**111,245**	68,566	55,292
OTHER INCOME (EXPENSE):			
Allowance for other funds used during construction	**1,718**	2,920	117
Interest accrued on deferred energy	**5,133**	5,163	10,644
Disallowed merger costs	**(1,929)**	—	—
Plant costs disallowed	**(47,092)**	—	—
Other income	**3,406**	4,403	4,266
Other expense	**(5,726)**	(6,767)	(6,577)
Income (taxes) benefits	**14,653**	(1,467)	(2,431)
	(29,837)	4,252	6,019
Total Income Before Interest Charges	**81,408**	72,818	61,311
INTEREST CHARGES:			
Long-term debt	**71,312**	76,002	66,474
Interest on terminated contracts (Note 14)	**(10,999)**	14,453	1,463
Other	**5,367**	8,914	9,200
Allowance for borrowed funds used during construction and capitalized interest	**(2,849)**	(3,276)	(1,858)
	62,831	96,093	75,279
NET INCOME (LOSS)	**18,577**	(23,275)	(13,968)
Preferred Dividend Requirements	**3,900**	3,900	3,900
EARNINGS (DEFICIT) APPLICABLE TO COMMON STOCK	**$ 14,677**	$ (27,175)	$ (17,868)

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)— SIERRA PACIFIC POWER COMPANY

Year ended December 31,	2004	2003	2002
(dollars in thousands)			
NET INCOME (LOSS)	**$18,577**	$(23,275)	$(13,968)
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX:			
Change in market value of risk management assets and liabilities as of December 31 (net of taxes of $(323), $(15), and $102 in 2004, 2003, and 2002, respectively)	**600**	28	(189)
Minimum pension liability adjustment (net of taxes of $65, $(83), and $349 in 2004, 2003, and 2002, respectively)	**(123)**	153	(649)
OTHER COMPREHENSIVE INCOME (LOSS)	**477**	181	(838)
COMPREHENSIVE INCOME (LOSS)	**$19,054**	$(23,094)	$(14,806)

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

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY— SIERRA PACIFIC POWER COMPANY

December 31,	2004	2003	2002
(dollars in thousands)			
COMMON STOCK:			
Balance at Beginning of Year and End of Year	**$ 4**	$ 4	$ 4
OTHER PAID-IN CAPITAL:			
Balance at Beginning of Year	**713,633**	713,633	703,633
Transfer of regulatory asset (Note 19)	**96,470**	—	10,000
Balance at End of Year	**810,103**	713,633	713,633
RETAINED EARNINGS (DEFICIT):			
Deficit at Beginning of Year	**(119,456)**	(73,751)	(10,983)
Income (loss) from continuing operations before preferred dividends	**18,577**	(23,275)	(13,968)
Preferred stock dividends declared	**(3,900)**	(3,900)	(3,900)
Common stock dividends declared	**—**	(18,530)	(44,900)
Deficit at End of Year	**(104,779)**	(119,456)	(73,751)
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):			
Balance at Beginning of Year	**(410)**	(591)	247
Adoption of SFAS No. 133—Accounting for Derivative Instruments and Hedging Activities			
Change in market value of risk management assets and liabilities as of December 31 (net of taxes of $(323), $(15), and $102 in 2004, 2003, and 2002, respectively)	**600**	28	(189)
Minimum pension liability adjustment (net of taxes of $65, $(83), and $349 in 2004, 2003, and 2002, respectively)	**(123)**	153	(649)
Balance at End of Year	**67**	(410)	(591)
TOTAL COMMON SHAREHOLDERS' EQUITY AT END OF YEAR	**$ 705,395**	$ 593,771	$639,295

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

CONSOLIDATED STATEMENTS OF CASH FLOWS— SIERRA PACIFIC POWER COMPANY

Year ended December 31,	**2004**	2003	2002
(dollars in thousands)			
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income (Loss)	**$ 18,577**	$ (23,275)	$ (13,968)
Non-cash items included in net income (loss):			
Depreciation and amortization	**86,806**	81,514	76,373
Deferred taxes and deferred investment tax credit	**11,640**	(23,676)	(5,107)
AFUDC	**(4,567)**	(6,196)	(1,975)
Amortization of deferred energy costs—electric	**36,653**	45,524	30,164
Amortization of deferred energy costs—gas	**3,241**	13,095	13,231
Deferred energy costs disallowed	**—**	45,000	58,928
Early retirement and severance amortization	**—**	2,786	2,706
Plant costs disallowed	**47,092**	—	—
Other non-cash	**474**	(5,203)	(4,093)
Changes in certain assets and liabilities:			
Accounts receivable	**(19,677)**	23,557	(18,803)
Deferral of energy costs—electric	**(34,598)**	(48,236)	(96,127)
Deferral of energy costs—gas	**(7,480)**	2,592	10,270
Materials, supplies, and fuel	**7,113**	3,278	880
Other current assets	**(10,086)**	(18,363)	(7,020)
Accounts payable	**2,153**	(30,516)	(24,308)
Income tax receivable	**—**	—	62,109
Escrow payment for terminating supplier	**(10,818)**	—	—
Other current liabilities	**5,567**	99,904	5,088
Other assets	**8,959**	26,055	(856)
Other liabilities	**(13,770)**	(112,673)	88,145
Net Cash provided by Operating Activities	**127,279**	75,167	175,637
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to utility plant	**(131,927)**	(149,951)	(107,364)
AFUDC and other charges to utility plant	**4,567**	6,196	1,975
Customer advances for construction	**8,130**	5,733	2,872
Contributions in aid of construction	**15,754**	11,437	7,447
Net cash used for utility plant	**(103,476)**	(126,585)	(95,070)
Disposal of subsidiaries and other property—net	**(82)**	(43)	993
Net Cash used in Investing Activities	**(103,558)**	(126,628)	(94,077)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Increase (decrease) in short-term borrowings	**(25,000)**	25,000	(46,500)
Change in restricted cash and investments	**3,130**	829	(9,605)
Proceeds from issuance of long-term debt	**100,000**	—	100,000
Retirement of long-term debt	**(99,491)**	(19,989)	(9,512)
Investment by parent company	**—**	—	10,000
Dividends paid	**(3,900)**	(22,430)	(48,805)
Net Cash used in Financing Activities	**(25,261)**	(16,590)	(4,422)
Net Increase (Decrease) in Cash and Cash Equivalents	**(1,540)**	(68,051)	77,138
Beginning Balance in Cash and Cash Equivalents	**20,859**	88,910	11,772
Ending Balance in Cash and Cash Equivalents	**$ 19,319**	$ 20,859	$ 88,910
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION:			
Cash paid (received) during period for:			
Interest	**$ 77,529**	$ 85,088	$ 73,409
Income taxes	**$ —**	$ (1,521)	$ (62,109)
NON-CASH ACTIVITIES:			
Transfer of Regulatory Asset (Note 19)	**$ 96,470**	$ —	$ —

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

CONSOLIDATED STATEMENTS OF CAPITALIZATION— SIERRA PACIFIC POWER COMPANY

December 31,	2004	2003
(dollars in thousands)		
COMMON SHAREHOLDERS' EQUITY:		
Common stock, $3.75 par value, 1,000 shares authorized, issued and outstanding	**$ 4**	$ 4
Other paid-in capital	**810,103**	713,633
Retained deficit	**(104,779)**	(119,456)
Accumulated other comprehensive income (loss)	**67**	(410)
Total Common Shareholders' Equity	**705,395**	593,771
CUMULATIVE PREFERRED STOCK:		
Not subject to mandatory redemption; 2,000,000 shares outstanding; $25 stated value	**50,000**	50,000
SPPC Class A Series 1; $1.95 dividend		
Long-Term Debt:		
Secured Debt		
Debt Secured by First Mortgage Bonds		
Revenue Bonds		
6.35% Series 1992B due 2012	**1,000**	1,000
6.55% Series 1987 due 2013	**39,500**	39,500
6.30% Series 1987 due 2014	**45,000**	45,000
6.65% Series 1987 due 2017	**92,500**	92,500
6.55% Series 1990 due 2020	**20,000**	20,000
6.30% Series 1992A due 2022	**10,250**	10,250
5.90% Series 1993A due 2023	**9,800**	9,800
5.90% Series 1993B due 2023	**30,000**	30,000
6.70% Series 1992 due 2032	**21,200**	21,200
Medium Term Notes		
6.62% to 6.83% Series C due 2006	**50,000**	50,000
6.95% to 8.61% Series A due 2022	**110,000**	110,000
7.10% to 7.14% Series B due 2023	**58,000**	58,000
Subtotal	**487,250**	487,250
General and Refunding Mortgage Securities		
10.50% (Variable) Series C due 2005	**—**	99,000
8.00% Series A due 2008	**320,000**	320,000
6.25% Series H due 2012	**100,000**	—
Subtotal	**420,000**	419,000
Debt Secured by General and Refunding Mortgage Securities		
Series L due October 22, 2007 (Union Bank of California, N.A. Credit Agreement)	**—**	—
7.50% Series 2001 due 2036	**—**	80,000
5.00% Series 2001 due 2036	**80,000**	—
Subtotal	**80,000**	80,000
Unsecured Debt		
Unamortized bond premium and discount, net	**(741)**	(2,650)
Obligations under capital leases	**—**	—
Current maturities and sinking fund requirements	**(2,400)**	(83,400)
Other, excluding current portion	**10,200**	12,600
Total Long-Term Debt	**994,309**	912,800
TOTAL CAPITALIZATION	**$1,749,704**	$1,556,571

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

NOTES TO FINANCIAL STATEMENTS

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The significant accounting policies for both utility and non-utility operations are as follows:

Basis of Presentation

The consolidated financial statements include the accounts of Sierra Pacific Resources (SPR) and its wholly owned subsidiaries, Nevada Power Company (NPC), Sierra Pacific Power Company (SPPC), Tuscarora Gas Pipeline Company (TGPC), Sierra Pacific Communications (SPC), Lands of Sierra, Inc. (LOS), Sierra Energy Company dba e·three (e·three), Sierra Pacific Energy Company (SPE), Sierra Water Development Company (SWDC) and Sierra Gas Holding Company (SGHC). SPC and e·three are discontinued operations and as such are reported separately in the financial statements. NPC and SPPC are referred to together in this report as the Utilities. All significant intercompany balances and intercompany transactions have been eliminated in consolidation.

The preparation of consolidated 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 certain assets and liabilities. These estimates and assumptions also affect the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of certain revenues and expenses during the reporting period. Actual results could differ from these estimates.

NPC is an operating public utility that provides electric service in Clark County in southern Nevada. The assets of NPC represent approximately 65% of the consolidated assets of SPR at December 31, 2004. NPC provides electricity to approximately 738,000 customers in the communities of Las Vegas, North Las Vegas, Henderson, Searchlight, Laughlin and adjoining areas, including Nellis Air Force Base. Service is also provided to the Department of Energy's Nevada Test Site in Nye County. The consolidated financial statements of SPR include NPC's wholly owned subsidiary, Nevada Electric Investment Company (NEICO).

SPPC is an operating public utility that provides electric service in northern Nevada and northeastern California. SPPC also provides natural gas service in the Reno/Sparks area of Nevada. The assets of SPPC represent approximately 34% of the consolidated assets of SPR at December 31, 2004. SPPC provides electricity to approximately 342,000 customers in a 50,000 square mile service area including western, central, and northeastern Nevada, including the cities of Reno, Sparks, Carson City, and Elko, and a portion of eastern California, including the Lake Tahoe area. SPPC also provides natural gas service in Nevada to approximately 135,000 customers in an area of about 600 square miles in the Reno and Sparks areas. The consolidated financial statements of SPPC include the accounts of SPPC's wholly owned subsidiaries, Piñon Pine Corporation, Piñon Pine Investment Company, GPSF-B, SPPC Funding LLC, and Sierra Pacific Power Capital I.

The Utilities' accounts for electric operations and SPPC's accounts for gas operations are maintained in accordance with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission (FERC).

TGPC is a partner in a joint venture that developed, constructed, and operates a natural gas pipeline serving the expanding gas market in the Reno area and certain northeastern California markets. TGPC accounts for its joint venture interest under the equity method. SPC was formed in 1999 to provide telecommunications services using fiber optic cable technology in both northern and southern Nevada.

Reclassifications

Certain reclassifications of prior years information have been made for comparative purposes but have not affected previously reported net income (loss) or common shareholders' equity.

Regulatory Accounting and Other Regulatory Assets

The Utilities' rates are currently subject to the approval of the Public Utilities Commission of Nevada (PUCN) and, in the case of SPPC, rates are also subject to the approval of the California Public Utility Commission (CPUC) and are designed to recover the cost of providing generation, transmission and distribution services. As a result, the Utilities qualify for the application of Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," issued by the Financial Accounting Standards Board (FASB). This statement recognizes that the rate actions of a regulator can provide reasonable assurance of the existence of an asset and requires the deferral of incurred costs that would otherwise be charged to expense where it is probable that future revenue will be provided to recover these costs. SFAS No. 71 prescribes the method to be used to record the financial transactions of a regulated entity. The criteria for applying SFAS No. 71 include the following: (i) rates are set by an independent third party regulator; (ii) regulated rates are designed to recover the specific costs of the regulated products or services; and (iii) it is reasonable to assume that rates are set at levels that recovered costs can be charged to and collected from customers. Management periodically assesses whether the requirements for application of SFAS No. 71 are satisfied.

In addition to the deferral of energy costs discussed below, significant items to which SPR and the Utilities apply regulatory accounting include goodwill and other merger costs resulting from the 1999 merger of SPR and NPC, generation divestiture costs, and the loss on reacquired debt.

NOTES TO FINANCIAL STATEMENTS (continued)

Regulatory assets represent incurred costs that have been deferred because it is probable they will be recovered through future rates collected from customers. If at any time the incurred costs no longer meet these criteria, these costs are charged to earnings. Regulatory liabilities generally represent obligations to make refunds to customers for previous collections, except for cost of removal which represents the cost of removing future electric and gas assets. Management regularly assesses whether the regulatory assets are probable of future recovery by considering actions of regulators, current laws related to regulation, applicable regulatory environment changes and the status of any current and pending or potential deregulation legislation.

Currently, the electric utility industry is predominantly regulated on a basis designed to recover the cost of providing electric power to its retail and wholesale customers. If cost-based regulation were to be discontinued in the industry for any reason, including competitive pressure on the cost-based prices of electricity, profits could be reduced, and the Utilities might be required to reduce their asset balances to reflect a market basis less than cost. Discontinuance of cost-based regulation could also require affected utilities to write off their associated regulatory assets. Management cannot predict the potential impact, if any, of these competitive forces on the Utilities' future financial position and results of operations.

SIERRA PACIFIC RESOURCES

Other Regulatory Assets and Liabilities

	As of December 31, 2004					
		Receiving Regulatory Treatment				
DESCRIPTION	Remaining Amortization Period	Earning a Return	Not Earning a Return	Pending Regulatory Treatment	**2004 Total**	As of December 31, 2003 Total
(dollars in thousands)						
Regulatory Assets						
Early retirement and severance offers	Various thru 2004	$ —	$ —	$ —	**$ —**	$ 2,497
Loss on reacquired debt	Term of related debt	35,890	—	—	**35,890**	30,123
Plant assets	Various thru 2031	41,619	7,176	—	**48,795**	3,414
Nevada divestiture costs	Thru 5/12	33,009	—	—	**33,009**	35,164
Merger transition/transaction costs	Thru 5/14	—	35,518	—	**35,518**	14,185
Merger severance/relocation	Thru 5/14	—	19,909	—	**19,909**	21,375
Merger goodwill	Thru 5/44	—	288,112	—	**288,112**	19,070
California restructure costs	Thru 2008	1,958	—	1,946	**3,904**	4,368
Conservation programs	Thru 2005	2,500	—	8,616	**11,116**	8,361
Variable rate mechanism deferral	Thru 10/04	—	—	—	**—**	352
Other costs	Thru 2017	5,169	287	6,053	**11,509**	3,598
Total Regulatory Assets		$120,145	$351,002	$16,615	**$487,762**	$142,507
Regulatory Liabilities						
Cost of removal	Various	$211,940	$ —	$ —	**$211,940**	$174,717
Gain on property sales	Various thru 2007	24,026	360	—	**24,386**	39,312
SO2 allowances	Various thru 2011	1,169	—	—	**1,169**	4,129
Gas transportation contract	Thru 2011	—	20,000	—	**20,000**	—
Total Regulatory Liabilities		$237,135	$ 20,360	$ —	**$257,495**	$218,158

NEVADA POWER COMPANY

Other Regulatory Assets and Liabilities

DESCRIPTION	Remaining Amortization Period	As of December 31, 2004 — Receiving Regulatory Treatment — Earning a Return	Not Earning a Return	Pending Regulatory Treatment	2004 Total	As of December 31, 2003 Total
(dollars in thousands)						
Regulatory Assets						
Loss on reacquired debt	Term of related debt	$ 15,823	$ —	$ —	**$ 15,823**	$ 13,956
Nevada divestiture costs	Thru 3/12	20,252	—	—	**20,252**	21,886
Merger transition/transaction costs	Thru 3/14	—	24,867	—	**24,867**	7,652
Merger severance/relocation	Thru 3/14	—	9,437	—	**9,437**	10,209
Merger goodwill	Thru 3/44	—	193,048	—	**193,048**	—
Conservation programs	Thru 2005	1,594	—	6,768	**8,362**	6,809
Other costs	Various thru 2008	2,368	133	3,160	**5,661**	209
Total Regulatory Assets		$ 40,037	$227,485	$9,928	**$277,450**	$ 60,721
Regulatory Liabilities						
Cost of removal	Various	$125,776	$ —	$ —	**$125,776**	$104,446
Gain on property sales	Various thru 2007	24,025	360	—	**24,385**	39,312
SO2 allowances	Various thru 2011	1,169	—	—	**1,169**	4,129
Gas transportation contract	Thru 2011	—	20,000	—	**20,000**	—
Total Regulatory Liabilities		$150,970	$ 20,360	$ —	**$171,330**	$147,887

SIERRA PACIFIC POWER COMPANY

Other Regulatory Assets and Liabilities

DESCRIPTION	Remaining Amortization Period	As of December 31, 2004 — Receiving Regulatory Treatment — Earning a Return	Not Earning a Return	Pending Regulatory Treatment	2004 Total	As of December 31, 2003 Total
(dollars in thousands)						
Regulatory Assets						
Early retirement and severance offers	Various thru 2004	$ —	$ —	$ —	**$ —**	$ 2,497
Loss on reacquired debt	Term of related debt	20,067	—	—	**20,067**	16,167
Plant assets	Various thru 2031	41,619	7,176	—	**48,795**	3,414
Nevada divestiture costs	Thru 5/12	12,757	—	—	**12,757**	13,278
Merger transition/transaction costs	Thru 5/14	—	10,651	—	**10,651**	6,533
Merger severance/relocation	Thru 5/14	—	10,472	—	**10,472**	11,166
Merger goodwill	Thru 5/44	—	95,064	—	**95,064**	—
California restructure costs	Thru 2008	1,958	—	1,946	**3,904**	4,368
Conservation programs	Thru 2005	906	—	1,848	**2,754**	1,552
Variable rate mechanism deferral	Thru 10/04	—	—	—	**—**	352
Other costs	Various thru 2017	2,801	154	2,893	**5,848**	3,389
Total Regulatory Assets		$80,108	$123,517	$6,687	**$210,312**	$62,716
Regulatory Liabilities						
Cost of removal	Various	$86,164	$ —	$ —	**$ 86,164**	$70,271
Gain on property sales	Thru 2005	1	—	—	**1**	—
Total Regulatory Liabilities		$86,165	$ —	$ —	**$ 86,165**	$70,271

NOTES TO FINANCIAL STATEMENTS (continued)

Deferral of Energy Costs

Nevada and California statutes permit regulated utilities to, from time-to-time, adopt deferred energy accounting procedures. The intent of these procedures is to ease the effect on customers of fluctuations in the cost of purchased gas, fuel, and purchased power.

In January 2000, in accordance with a PUCN order SPPC resumed using deferred energy accounting for its gas operations.

On April 18, 2001, the Governor of Nevada signed into law AB 369. The provisions of AB 369 include, among others, a reinstatement of deferred energy accounting for fuel and purchased power costs incurred by electric utilities. In accordance with the provisions of SFAS No. 71, the Utilities implemented deferred energy accounting on March 1, 2001, for their respective electric operations. Under deferred energy accounting, to the extent actual fuel and purchased power costs exceed fuel and purchased power costs recoverable through current rates, that excess is not recorded as a current expense on the statement of operations but rather is deferred and recorded as an asset on the balance sheet. Conversely, a liability is recorded to the extent fuel and purchased power costs recoverable through current rates exceed actual fuel and purchased power costs. These excess amounts are reflected in adjustments to rates and recorded as revenue or expense in future time periods, subject to PUCN review.

Pursuant to AB 369, Nevada Revised Statute (NRS) requires the Utilities to file applications to clear their respective deferred energy account balances at least every 12 months and provides that the PUCN may not allow the recovery of any costs for purchased fuel or purchased power "that were the result of any practice or transaction that was undertaken, managed or performed imprudently by the electric utility." In reference to deferred energy accounting, NRS specifies that fuel and purchased power costs include all costs incurred to purchase fuel, to purchase capacity, and to purchase energy. The Utilities also record and are eligible under the statute to recover a carrying charge on such deferred balances.

The following deferred energy costs were included in the consolidated balance sheets as of the dates shown (dollars in thousands):

	December 31, 2004			
DESCRIPTION	**NPC Electric**	**SPPC Electric**	**SPPC Gas**	**SPR Total**
Unamortized balances approved for collection in current rates(1)	**$134,574**	**$ 50,783**	**$ (684)**	**$184,673**
Balances pending PUCN approval(2)	**115,752**	**27,676**	**—**	**143,428**
Cumulative CPUC balance	**—**	**5,101**	**—**	**5,101**
Balances accrued since end of periods submitted for PUCN approval	**10,829**	**5,380**	**6,281**	**22,490**
Claims for terminated supply contracts(3)	**240,039**	**84,033**	**—**	**324,072**
Total	**$501,194**	**$172,973**	**$ 5,597**	**$679,764**
Current Assets				
Deferred energy costs—electric	**$126,074**	**$ 21,934**	**$ —**	**$148,008**
Deferred energy costs—gas	**—**	**—**	**3,106**	**3,106**
Deferred Assets				
Deferred energy costs—electric	**375,120**	**151,039**	**—**	**526,159**
Deferred energy costs—gas	**—**	**—**	**2,491**	**2,491**
Total	**$501,194**	**$172,973**	**$ 5,597**	**$679,764**

	December 31, 2003			
DESCRIPTION	NPC Electric	SPPC Electric	SPPC Gas	SPR Total
Unamortized balances approved for collection in current rates	$274,164	$ 45,039	$ 941	$320,144
Balances pending PUCN approval	91,323	42,398	—	133,721
Cumulative CPUC balance	—	—	—	—
Balances accrued since end of periods submitted for PUCN approval	8,477	3,559	417	12,453
Claims for terminated supply contracts(3)	244,590	84,032	—	328,622
Total	$618,554	$175,028	$1,358	$794,940
Current Assets				
Deferred energy costs—electric	$247,249	$ 48,428	$ —	$295,677
Deferred energy costs—gas	—	—	1,358	1,358
Deferred Assets				
Deferred energy costs—electric	371,305	126,600	—	497,905
Deferred energy costs—gas	—	—	—	—
Total	$618,554	$175,028	$1,358	$794,940

(1) Credits represent over-collections, that is, the extent to which gas or fuel and purchased power costs recovered through rates exceed actual gas or fuel and purchased power costs.

(2) On February 22, 2005, a stipulation of the parties was filed with the PUCN resolving all issues in the NPC case. The stipulation provides for an overall decrease of 0.6% in total rates with no disallowances. The PUCN approved the stipulation in total on March 16, 2005.

(3) Amounts related to claims for terminated supply contracts are discussed in Note 14, Commitments and Contingencies.

Utility Plant

The cost of additions, including betterments and replacements of units of property, is charged to utility plant. When units of property are replaced, renewed or retired, their cost, plus removal or disposal costs, less salvage, is charged to accumulated depreciation. The cost of current repairs and minor replacements is charged to operating expenses when incurred.

In addition to direct labor and material costs, certain other direct and indirect costs are capitalized, including the cost of debt and equity capital associated with construction and retirement activity. The indirect construction overhead costs capitalized are based upon the following cost components: the cost of time spent by administrative employees in planning and directing construction; property taxes; employee benefits including such costs as pensions, post retirement and post employment benefits, vacations and payroll taxes; and an allowance for funds used during construction (AFUDC).

Allowance For Funds Used During Construction

As part of the cost of constructing utility plant, the Utilities capitalize AFUDC. AFUDC represents the cost of borrowed funds and, where appropriate, the cost of equity funds used for construction purposes in accordance with rules prescribed by the FERC and the PUCN. AFUDC is capitalized in the same manner as construction labor and material costs, with an offsetting credit to "other income" for the portion representing the cost of equity funds and as a reduction of interest charges for the portion representing borrowed funds. Recognition of this item as a cost of utility plant is in accordance with established regulatory ratemaking practices. Such practices are intended to permit the Utility to earn a fair return on, and recover in rates charged for utility services, all capital costs. This is accomplished by including such costs in the rate base and in the provision for depreciation. NPC's AFUDC rates used during 2004, 2003, and 2002 were 9.03%, 8.37%, and 4.72% respectively. SPPC's AFUDC rates used during 2004, 2003, and 2002 were 9.26%, 8.61%, and 5.54% respectively. As specified by the PUCN, certain projects may be assigned a lower AFUDC rate due to specific low-interest-rate financings directly associated with those projects.

Depreciation

Substantially all of the Utilities' plant is subject to the ratemaking jurisdiction of the PUCN or the FERC, and, in the case of SPPC, the CPUC, which also approves any changes the Utilities may make to depreciation rates utilized for this property. Depreciation is calculated using the straight-line composite method over the estimated remaining service lives of the related properties, which approximates the anticipated physical lives of these assets in most cases. NPC's depreciation provision for 2004, 2003, and 2002, as authorized by the PUCN and stated as a percentage of the original cost of depreciable property, was approximately 3.05%, 3.06%, and 3.0% respectively. SPPC's depreciation provision for 2004, 2003, and 2002, as authorized by the PUCN and stated as a percentage of the original cost of depreciable property, was approximately 3.35%, 3.31%, and 3.33% respectively.

Impairment of Long-Lived Assets

SPR, NPC, and SPPC evaluate on an ongoing basis the recoverability of its assets for impairments whenever events or changes in circumstance indicate that the carrying amount may not be recoverable as described in SFAS No. 144 "Accounting for the Disposal or Impairment of Long-Lived Assets." (SFAS 144) See Note 18, Discontinued Operations and Disposal and Impairment of Long-Lived Assets.

Accounting For Goodwill

SFAS No. 142 "Goodwill and Other Intangible Assets," adopted by SPR, NPC and SPPC on January 1, 2002, changed the accounting for goodwill from an amortization method to one requiring at least an annual review for impairment. In the year ended 2002, upon adoption, SPR ceased amortizing goodwill and recorded a cumulative effect of change in accounting principle, net of tax, of $1.6 million, due to an impairment associated with SPR's unregulated subsidiaries. See Note 19, Goodwill and Other Merger Costs for further discussion.

Cash and Cash Equivalents

Cash is comprised of cash on hand and working funds. Cash equivalents consist of high quality investments in money market funds.

Restricted Cash

At December 31, 2004 and 2003, SPR had approximately $88.5 million and $54.7 million, respectively of restricted cash in SPR's consolidated balance sheets, primarily consisting of an aggregate $49 million and $11 million in cash collateral deposited by NPC and SPPC, respectively, into escrow in connection with the stay of the Enron Judgment, as described in Note 14, Commitments and Contingencies, and cash collateral restricted for debt service payments for the $300 million convertible notes, discussed in Note 7, Long-Term Debt. The remaining amount consists mainly of cash balances that are required to be maintained by financial institutions due to the financial condition of SPR, NPC, and SPPC.

Federal Income Taxes

SPR and its subsidiaries file a consolidated federal income tax return. Current income taxes are allocated based on SPR's and each subsidiary's respective taxable income or loss and investment tax credits as if each subsidiary filed a separate return. SPR accounts for income taxes in accordance with SFAS No. 109, "Accounting for Income Taxes." SFAS No. 109 requires recognition of deferred tax liabilities and assets for the future tax consequences of events that have been included in the consolidated financial statements or tax returns. Under this method, deferred tax liabilities and assets are determined based on the difference between the financial statement and tax basis of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse.

NOTES TO FINANCIAL STATEMENTS (continued)

For regulatory purposes, the Utilities are authorized to provide for deferred taxes on the difference between straight-line and accelerated tax depreciation on post-1969 utility plant expansion property, deferred energy, and certain other differences between financial reporting and taxable income, including those added by the Tax Reform Act of 1986 (TRA). In 1981, the Utilities began providing for deferred taxes on the benefits of using the Accelerated Cost Recovery System for all post-1980 property. In 1987, the TRA required the Utilities to begin providing deferred taxes on the benefits derived from using the Modified Accelerated Cost Recovery System.

Deferred investment tax credits are being amortized over the estimated service lives of the related properties. Investment tax credits are no longer available to the Utilities.

Revenues

Operating revenues include billed and unbilled utility revenues. The accrual for unbilled revenues represents amounts owed to the Utilities for service provided to customers for which the customers have not yet been billed. These unbilled amounts are also included in accounts receivable.

Revenues related to the sale of energy are recorded based on meter reads, which occur on a systematic basis throughout a month, rather than when the service is rendered or energy is delivered. At the end of each month, the energy delivered to the customers from the date of their last meter read to the end of the month is estimated and the corresponding unbilled revenues are calculated. These estimates of unbilled sales and revenues are based on the ratio of billable days versus unbilled days, amount of energy procured and generated during that month, historical customer class usage patterns and the Utilities' current tariffs. Accounts receivable as of December 31, 2004, include unbilled receivables of $83 million and $67 million for NPC and SPPC, respectively. Accounts receivable as of December 31, 2003, include unbilled receivables of $63 million and $56 million for NPC and SPPC, respectively.

Stock Compensation Plans

At December 31, 2004, SPR had several stock-based compensation plans, which are described more fully in Note 13, Stock Compensation Plans. SPR applies Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees," in accounting for its stock option plans and in accordance with the disclosure only provisions of SFAS No. 123, "Accounting for Stock-Based Compensation," and the updated disclosure requirements set forth in SFAS No. 148 "Accounting for Stock-Based Compensation-Transition and Disclosure." Accordingly, no compensation cost has been recognized for nonqualified stock options and the employee stock purchase plan. SPR will be adopting SFAS No. 123R "Share-Based Payment" beginning in the third quarter of 2005. See SFAS 123 (R) discussed later. Had compensation cost for SPR's nonqualified stock options and the employee stock purchase plan been determined based on the fair value at the grant dates for awards under those plans, consistent with the accounting provisions of SFAS No. 123, SPR's Earnings (Loss) applicable to common stock would have been decreased to the pro forma amounts indicated in the table below (dollars in thousands, except per share amounts).

		2004	2003	2002
Earnings (deficit) applicable to common stock, as reported		**$28,571**	$(140,529)	$(307,521)
Add: Stock compensation cost included in net income as reported, net of related tax effects		**1,958**	410	(1,567)
Less: Pro forma stock compensation cost, net of related tax effects		**(2,158)**	(1,750)	(480)
Pro forma earnings (deficit) applicable to common stock		**$28,371**	$(141,869)	$(309,568)
Basic earnings (deficit) per share	As reported	**$ 0.16**	$ (1.21)	$ (3.01)
	Pro forma	**$ 0.16**	$ (1.22)	$ (3.03)
Diluted earnings (deficit) per share	As reported	**$ 0.16**	$ (1.21)	$ (3.01)
	Pro forma	**$ 0.16**	$ (1.22)	$ (3.03)

Asset Retirement Obligations

SFAS No. 143 "Accounting for Asset Retirement Obligations" provides accounting requirements for the recognition and measurement of liabilities associated with the retirement of tangible long-lived assets. Under the standard, these liabilities are 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 is classified as an operating expense. 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. SPR, NPC, and SPPC adopted SFAS No. 143 on January 1, 2003.

Management's methodology to assess its legal obligation included an inventory of assets by system and components and a review of rights of way and easements, regulatory orders, leases and federal, state, and local environmental laws. The Utilities have various transmission and distribution lines as well as substations that operate under various rights of way that contain end dates and restorative clauses. In determining its Asset Retirement Obligations, management assumes that transmission; distribution and communications systems will be operated in perpetuity and will continue to be used or sold without land remediation and that mass asset properties that are replaced or retired frequently will be considered normal maintenance. As a result, the Utilities have not recorded any costs associated with the removal of the transmission and distribution systems.

Management has identified a legal obligation to retire generation plant assets specified in land leases for NPC's jointly-owned Navajo generating station. The land on which the Navajo generating station resides is leased from the Navajo Nation. The provisions of the leases require the lessees to remove the facilities upon request of the Navajo Nation at the expiration of the leases. Management has determined that the present value of NPC's Navajo Asset Retirement Obligation did not have a material effect on the financial position or results of operations of SPR or NPC. SPPC has no significant asset retirement obligations.

Cost of Removal

In addition to the legal asset retirement obligation booked for the Navaho plant, the Utilities have accrued for the cost of removing non-legal retirement obligations of other electric and gas assets, in accordance with accepted accounting practices. The amount of such accruals included in regulatory liabilities in 2004 is approximately $126 million and $86 million for NPC and SPPC, respectively. In 2003, the amounts were approximately $104 million and $70 million for NPC and SPPC, respectively.

Recent Pronouncements

In December 2003, the FASB issued Interpretation No. 46, as revised December 2003 "Consolidation of Variable Interest Entities" (FIN 46 (R)), which elaborates on Accounting Research Bulletin No. 51, "Consolidated Financial Statements." Among other requirements, FIN 46 (R) provides that a variable interest entity be consolidated by the enterprise that is the primary beneficiary of the variable interest entity. As of December 31, 2003, SPR, NPC, and SPPC adopted FIN 46 (R) for special purpose entities. As of March 31, 2004, SPR, NPC and SPPC adopted FIN 46 (R) for all variable interest entities. To identify potential variable interests, management reviewed long term purchase power contracts, including contracts with qualifying facilities (QFs), jointly owned facilities and partnerships that are not consolidated. The Utilities identified seven QFs with long-term purchase power contracts that are variable interests. However, the Utilities are not required at this time to consolidate these QFs under the scope exception provided for in FIN 46 (R) due to the inability to obtain information necessary to (1) determine whether the entity is a variable interest entity, (2) determine whether the enterprise is the variable interest entity's primary beneficiary, or (3) perform the accounting required to consolidate the variable interest entity for which it is determined to be the primary beneficiary. The Utilities have requested financial information from these QFs but have not been successful in obtaining the information. The Utilities' maximum exposure to loss is limited to the cost of replacing these purchase power contracts if the QFs are unable to deliver power. However, the Utilities believe their exposure is mitigated as they would likely recover these costs through their deferred energy accounting mechanism. The Utilities have not identified any other significant variable interests that require consolidation as of December 31, 2004.

FSP FAS 106-2

The FASB issued a Staff Position (FSP) to modify FSP FAS 106-2 in May 2004 to provide guidance on accounting for the effects of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act), signed into law on December 8, 2003. This FSP supersedes FSP FAS 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003", under which the Company elected to defer implementation due to the lack of definitive guidelines from the FASB and the Department of Health and Human Services. SPR has concluded that its prescription drug plan would qualify for the federal subsidy under this Act.

FSP FAS 106-2 applies only to sponsors of single-employer defined benefit postretirement health care plans for which (1) the employer has concluded that prescription drug benefits available under the plan to some or all participants, for some or all future years, are "actuarially equivalent" to Medicare Part D and thus qualify for the subsidy provided by the Act, and (2) the expected subsidy will offset or reduce the employer's share of the cost of the underlying postretirement prescription drug coverage on which the subsidy is based. The FSP provides guidance on measuring the accumulated postretirement benefit obligation (APBO) and net periodic postretirement benefit cost, and the effects of the Act on APBO. In addition, the FSP addresses accounting for plan amendments, and requires certain disclosures about the Act and its effects on financial statements. The effect of the subsidy on the APBO for benefits attributable to past service will be accounted for as an actuarial experience gain pursuant to SFAS 106. Because the subsidy affects the employer's share of its plan's costs, the subsidy is included in measuring the costs of benefits attributable to current service. Therefore, the subsidy reduces service cost when it is recognized as a component of net periodic postretirement benefit cost. The FSP allows for either prospective recognition from the date of adoption or retroactive recognition by restating prior quarters for the effect of the change. The latter treatment will allow for the recognition of the cumulative effect of change on prior year's financial statements, if material, but will not require statements to be reissued. The FSP is effective for the first interim or annual period beginning after June 15, 2004.

Final guidelines were issued by the Department of Health and Human Services on July 26, 2004, and SPR completed its evaluation of the impact of this Act on its postretirement benefit expense. SPR elected to adopt FSP FAS 106-2 prospectively, valuing the annual benefit of the subsidy as of April 1, 2004, and recognizing one half of this amount in the third and fourth quarters. (The April 1 valuation was required for companies using an annual measurement date of September 30 for pension plans, and electing to adopt FSP FAS 106-2 prospectively.) The valuation resulted in an annual reduction to other postretirement benefit costs of $0.8 million. Accordingly, SPR recognized $0.2 million in each of the third and fourth quarters of 2004. Also refer to Note 12, Retirement Plan and Postretirement Benefits.

NOTES TO FINANCIAL STATEMENTS (continued)

FSP FAS 129-1

In April 2004, the FASB issued FSP FAS 129-1, "Disclosure Requirements under FASB Statement No. 129, Disclosure of Information about Capital Structure, relating to Contingently Convertible Securities" to provide disclosure guidance for contingently convertible securities, including those instruments with contingent conversion requirements that have not been met and otherwise are not required to be included in the computation of diluted earnings per share. In order to comply with the requirements of SFAS 129, the significant terms of the conversion features of the contingently convertible security should be disclosed including: (i) events or changes in circumstances that would cause the contingency to be met and any significant features necessary to understand the conversion rights and the timing of the rights, (ii) the conversion price and the number of shares into which the security is potentially convertible, (iii) events or changes in circumstances, if any, that could adjust or change the contingency, conversion price, or number of shares, including significant terms of those changes and (iv) the manner of settlement upon conversion and any alternative methods. SPR has adopted and implemented the disclosure requirements of FSP FAS 129-1. See Note 7, Long-Term Debt.

EITF 03-6

The Emerging Issues Task Force (EITF) of the FASB nullified the guidelines given in EITF Topic D-95 with regards to the effect of participating convertible securities on the computation of basic earnings per share by issuing EITF 03-6, Participating Securities and the Two-Class Method under FASB Statement No. 128. Under Topic D-95 (see Note 17, Earnings Per Share), companies were required to use either the "two-class" or the "if-converted" method to account for potential dilution due to participating convertible securities that could be converted into common stock, if the effect was dilutive. This was to be used in the calculation of basic and diluted earnings per share.

Accordingly, SPR included the dilutive effects of its convertible 7.25% notes due 2010, or Convertible Notes, in its financial statements for the three months ended September 30, 2003 using the "if-converted" method. The impact of conversion was deemed to be anti-dilutive for all other periods in 2003 and 2004 when Topic D-95 was effective. EITF 03-6 now requires using the "two-class" method to record the effect of participating securities in the computation of basic earnings per share, and the "if-converted" method in the computation of diluted earnings per share.

The FASB ratified the consensus reached by the EITF on Issue 03-6 on March 31, 2004, and made it effective for fiscal periods commencing after this date. SPR has adopted the "two-class" method to show the potential dilutive effect of its Convertible Notes in the computation of basic earnings per share for all financial statements issued after March 31, 2004.

FAS 123(R)

The FASB issued Statement of Financial Accounting Standard No. 123 (revised 2004), "Share-Based Payment", (SFAS 123(R) in December 2004, which requires all public companies to measure and recognize the fair value of equity instrument awards granted to employees. SFAS 123(R) is effective for periods beginning after June 15, 2005 for most companies, and amends the current accounting standard, SFAS 123, which has been in effect since 1995. The new standard is similar to SFAS 123, but will now require recognition of costs using fair value accounting for companies that opted to follow the guidance of APB 25 to account for stock compensation costs. SFAS 123(R) does not require companies to use a specific valuation methodology, but it does indicate a clear preference for the use of complex "lattice models" rather than a traditional Black-Scholes model. SPR will use the fair-value method to recognize stock compensation costs commencing in the third quarter of 2005, using the modified prospective method of adoption. New awards and awards modified, repurchased or cancelled after July 1, 2005 will be accounted for under the new standard. Awards granted prior to this date for which the required service is yet to be rendered will also receive similar treatment. Amounts that were previously shown in footnote disclosure by SPR will now be recognized in the income statement. SPR intends to utilize the services of its actuaries to value share-based compensation.

NOTE 2. SEGMENT INFORMATION

SPR's Utilities operate three regulated business segments (as defined by SFAS 131, "Disclosure about Segments of an Enterprise and Related Information"); which are NPC electric, SPPC electric and SPPC natural gas service. Electric service is provided to Las Vegas and surrounding Clark County by NPC, northern Nevada and the Lake Tahoe area of California by SPPC. Natural gas services are provided by SPPC in the Reno-Sparks area of Nevada. Other segment information includes segments below the quantitative threshold for separate disclosure.

The net assets and operating results of SPC and e·three are reported as discontinued operations in the financial statements for 2004, 2003 and 2002. Accordingly, the segment information excludes financial information of SPC and e·three.

Operational information of the different business segments is set forth below based on the nature of products and services offered. SPR evaluates performance based on several factors, of which, the primary financial measure is business segment operating income. The accounting policies of the business segments are the same as those described in Note 1, Summary of Significant Accounting Policies. Inter-segment revenues are not material (dollars in thousands).

December 31, 2004	**NPC Electric**	**SPPC Electric**	**Total Electric**	**Gas**	**All Other**	**Reconciling Eliminations**	**Consolidated**
Operating revenues	**$1,784,092**	**$ 881,908**	**$2,666,000**	**$153,752**	**$ 4,087**	**$ —**	**$2,823,839**
Operating income	**216,490**	**103,513**	**320,003**	**7,732**	**11,050**	**—**	**338,785**
Operating income taxes	**45,135**	**12,740**	**57,875**	**2,238**	**(35,670)**	**—**	**24,443**
Depreciation	**118,841**	**79,298**	**198,139**	**7,508**	**—**	**—**	**205,647**
Interest expense on long-term debt	**152,764**	**64,729**	**217,493**	**6,583**	**88,323**	**—**	**312,399**
Assets	**4,883,540**	**2,226,949**	**7,110,489**	**232,092**	**120,607**	**65,279**	**7,528,467**
Capital expenditures	**482,484**	**117,329**	**599,813**	**14,598**	**—**	**—**	**614,411**

December 31, 2003	NPC Electric	SPPC Electric	Total Electric	Gas	All Other	Reconciling Eliminations	Consolidated
Operating revenues	$1,756,146	$ 868,280	$2,624,426	$161,586	$ 1,531	$ —	$2,787,543
Operating income	183,733	61,323	245,056	7,243	19,165	—	271,464
Operating income taxes	(12,734)	(14,288)	(27,022)	584	(30,570)	—	(57,008)
Depreciation	109,655	74,432	184,087	7,082	90	—	191,259
Interest expense on long-term debt	142,143	69,888	212,031	6,114	75,337	—	293,482
Assets	4,210,759	2,061,255	6,272,014	230,365	490,530	70,849	7,063,758
Capital expenditures	229,368	127,014	356,382	22,937	—	—	379,319

December 31, 2002	NPC Electric	SPPC Electric	Total Electric	Gas	All Other	Reconciling Eliminations	Consolidated
Operating revenues	$1,901,034	$ 931,251	$2,832,285	$149,783	$ 2,536	$ —	$2,984,604
Operating income	(104,003)	49,944	(54,059)	5,348	21,203	—	(27,508)
Operating income taxes	(133,411)	(7,236)	(140,647)	314	(24,916)	—	(165,249)
Depreciation	98,198	70,190	168,388	6,183	(371)	—	174,200
Interest expense on long-term debt	114,527	62,004	176,531	4,470	67,851	—	248,852
Assets	4,166,988	2,104,460	6,271,448	228,067	486,135	124,989	7,110,639
Capital expenditures	296,966	92,380	389,346	14,984	—	—	404,330

The reconciliation of segment assets at December 31, 2004, 2003, and 2002 to the consolidated total includes the following unallocated amounts:

	2004	2003	2002
Cash	**$35,783**	$29,635	$ 98,515
Current assets—other	**—**	—	—
Other regulatory assets	**21,124**	31,812	24,555
Net assets—discontinued operations	**—**	—	—
Deferred charges—other	**8,372**	9,402	1,919
	$65,279	$70,849	$124,989

NOTE 3. REGULATORY ACTIONS

The Utilities are subject to the jurisdiction of the PUCN and, in the case of SPPC, the CPUC with respect to rates, standards of service, siting of and necessity for, generation and certain transmission facilities, accounting, issuance of securities and other matters with respect to electric distribution and transmission operations. NPC and SPPC submit Integrated Resource Plans (IRPs) to the PUCN for approval.

Under federal law, the Utilities and TGPC are subject to certain jurisdictional regulation, primarily by the FERC. The FERC has jurisdiction under the Federal Power Act with respect to rates, service, interconnection, accounting and other matters in connection with the Utilities' sale of electricity for resale and interstate transmission. The FERC also has jurisdiction over the natural gas pipeline companies from which the Utilities take service.

As a result of regulation, many of the fundamental business decisions of the Utilities, as well as the rate of return they are permitted to earn on their utility assets, are subject to the approval of governmental agencies.

As with other utilities, NPC and SPPC are subject to federal, state and local regulations governing air, water quality, hazardous and solid waste, land use and other environmental considerations. Nevada's Utility Environmental Protection Act requires approval of the PUCN prior to construction of major utility, generation or transmission facilities. The United States Environmental Protection Agency (EPA), Nevada Division of Environmental Protection (NDEP), and Clark County Health District (CCHD) administer regulations involving air quality, water pollution, solid, hazardous and toxic waste. SPR's Board of Directors has a comprehensive environmental policy and separate board committee that oversees NPC, SPPC, and SPR's corporate performance and achievements related to the environment.

NOTES TO FINANCIAL STATEMENTS (continued)

Deferred Energy Accounting

The Utilities began using deferred energy accounting for their respective electric operations in March 2001. The intent of deferred energy accounting is to ease the effect of fluctuations in the cost of purchased power and fuel.

Nevada Matters

Nevada Power Company 2003 General Rate Case

NPC filed its biennial General Rate Case on October 1, 2003, as required by law. On March 26, 2004, the PUCN issued an order allowing $48 million of the $133 million rate increase requested by NPC. The general rate decision reflects the following significant items:

- A Return on Equity (ROE) of 10.25%, and an overall Rate of Return (ROR) of 9.03%, an improvement over NPC's previous ROE and ROR, which were 10.1% and 8.37%, respectively. NPC had requested an ROE of 12.4% and ROR of 10.0%;
- Approximately $7 million of the $8.8 million of goodwill and merger costs requested to be recovered annually over each of the next two years;
- Approximately $21.4 million of generation divestiture costs to be recovered over an extended period of 8 years;
- Approved the establishment of a regulatory asset account to capture costs related to the shutdown of the Mohave Power Plant; and
- Required NPC to file a set of recommended quality of service and customer service measurements to be used in future general rate case proceedings. On July 1, 2004, NPC and SPPC jointly filed with the PUCN their recommended quality of service and customer service measurements. The PUCN opened up an investigatory docket to adjudicate the issues.

The PUCN removed from cost of service various items requested by NPC through its general rates filing including costs associated with NPC's 2003 short-term incentive compensation plan and NPC's request to earn a rate of return on the cash balances NPC maintained to ensure sufficient liquidity to procure power. In addition, the PUCN's decision included a decrease to NPC's general rates to allow NPC's customers to share the benefit of approximately $8.3 million per year for the next two years of gains from recent land sales by NPC.

The PUCN responded to petitions filed by the Bureau of Consumer Protection (BCP) and NPC on May 20, 2004 and June 7, 2004, respectively. The PUCN's May 20 order denied two of the issues on which the BCP requested reconsideration, and granted clarification on the third issue. The clarification addressing rental revenue resulted in an overall reduction in the revenue requirement of $1.6 million. The PUCN's June 7, 2004 order concluded that the petition was granted in part since clarification had been given on the requested issues and denied in part since NPC's requested revisions to the order were not accepted.

Nevada Power Company 2004 Deferred Energy Case

On November 15, 2004, NPC filed an application with the PUCN seeking repayment for purchased fuel and power costs accumulated between October 1, 2003 and September 30, 2004, as required by law. The application seeks to establish a rate to collect accumulated purchased fuel and power costs of $116 million, with a carrying charge. The application requests that the 2004 Deferred Energy Accounting Adjustment (DEAA) recovery begin with the expiration of the 2002 DEAA recovery, which is expected to occur in May 2006 and for the 2004 DEAA recovery period to be 22 months.

The application also requests an increase to the going-forward base tariff energy rate (BTER).

In concert with this 2004 DEAA filing, NPC filed a petition with the PUCN requesting that other pending DEAA rate changes be synchronized to change on April 1, 2005 in order to stabilize rates and reduce the number of rate changes. On December 28, 2004, the PUCN issued an order approving a stipulation reached by all parties that allows NPC to defer previously approved DEAA rate changes until April 1, 2005 coincident with the DEAA rate change that will result from the 2004 DEAA case.

The combined effect of the requested synchronization of multiple rate changes (going-forward BTER increase, 2001 DEAA expiration, 2003 DEAA initiation) resulted in a request for an overall rate decrease of 2.4%.

On February 22, 2005, a stipulation of the parties was filed with the PUCN resolving all issues in the case. The stipulation provides for an overall decrease of 0.6% in total rates with no disallowances. The PUCN approved the stipulation in total on March 16, 2005.

Nevada Power Company 2003 Deferred Energy Case

On November 14, 2003, NPC filed an application with the PUCN seeking repayment for purchased fuel and power costs accumulated between October 1, 2002 and September 30, 2003, as required by law. The application sought to establish a rate to collect accumulated purchased fuel and power costs of $93 million. On March 26, 2004, the PUCN granted approval for NPC to increase its going forward energy rate as filed, approved recovery for $89 million of its deferred balance, denied $4 million, and denied NPC's request for a tax gross-up on the equity portion of carrying charges. Of the $4 million disallowed, $1.6 million was charged to income in the current period as the remaining amount had no impact on earnings or was charged to income in prior periods. The PUCN ordered the change in going forward rates to take effect April 1, 2004 and delayed the implementation of the deferred energy balance recovery until January 1, 2005 when recovery of the 2001 deferred balance was expected to have been completed.

On December 28, 2004, the PUCN issued an order approving a stipulation reached by all parties that allows NPC to defer the 2003 DEAA rate change until April 1, 2005, which will be coincident with the DEAA rate change that will result from the 2004 DEAA case.

Nevada Power Company 2002 Deferred Energy Case

On November 14, 2002, NPC filed an application with the PUCN seeking repayment for purchased fuel and power costs accumulated between October 1, 2001, and September 30, 2002, as required by law. The application sought to establish a rate to collect accumulated purchased fuel and power costs of $195.7 million, together with a carrying charge, over a period of not more than three years. The application also requested a reduction to the going-forward rate for energy, reflecting reduced wholesale energy costs. The combined effect of these two adjustments resulted in a request for an overall rate reduction of approximately 6.3%.

The decision on this case was issued May 13, 2003, and authorized the following:

- recovery of $147.6 million, with a carrying charge, and a $48.1 million disallowance;
- a three-year amortization of the balance commencing on May 19, 2003;
- a reduction in the Base Tariff Energy Rate (BTER) to an effective non-residential rate of $0.04322 per kWh, and an effective residential rate of $0.04186 per kWh.

The new rates went into effect on May 19, 2003.

The BCP filed a Petition that challenged the recovery of all costs with the District Court of Clark County, Nevada, for Judicial Review of the PUCN Order on August 8, 2003, against PUCN, Case No. A471928. On September 8, 2003, the PUCN filed its answer to the BCP Petition. The PUCN response cites a number of affirmative defenses to the allegations contained in the BCP petition and asks that the court dismiss the BCP petition. The BCP filed its opening brief on January 8, 2004 and responding briefs were filed on March 9, 2004. The court has not yet ruled on this matter.

Nevada Power Company 2001 Deferred Energy Case

On November 30, 2001, NPC filed an application with the PUCN seeking repayment for purchased fuel and power costs accumulated between March 1, 2001, and September 30, 2001, as required by law. The application sought to establish a rate to repay accumulated purchased fuel and power costs of $922 million and spread the recovery of the deferred costs, together with a carrying charge, over a period of not more than three years.

On March 29, 2002, the PUCN issued its decision on the deferred energy application, allowing NPC to recover $478 million over a three-year period, but disallowing $434 million of deferred purchased fuel and power costs and $30.9 million in carrying charges consisting of $10.1 million in carrying charges accrued through September 2001 and $20.8 million in carrying charges accrued from October 2001 through February 2002. The order stated that the disallowance was based on alleged imprudence in incurring the disallowed costs. NPC and the BCP both sought individual review of the PUCN Order in the First District Court of Nevada. The District Court affirmed the PUCN's decision. Both NPC and the BCP filed Notices of Appeal to the Nevada Supreme Court. Supreme Court rules mandate settlement talks before a matter is set for briefing and argument. As a result of that mandatory process, NPC filed a motion with the Nevada Supreme Court seeking remand of the matter back to the PUCN to consider evidence uncovered after the PUCN's final decision. On November 2, 2004, the Nevada Supreme Court issued an order denying the motion for remand.

A briefing schedule on the underlying appeal has since been established. A decision is not expected for six to twelve months. At this time, NPC is unable to predict either the outcome or timing of a decision in this matter.

Sierra Pacific Power Company 2003 General Rate Case

SPPC filed its biennial general rate case on December 1, 2003, as required by law. SPPC requested an $87 million increase in the annual revenue requirement for general rates. On April 1, 2004, SPPC, the Staff of the Public Utilities Commission of Nevada and other interveners in SPPC's 2003 general rate case negotiated a settlement agreement that resolved most of the issues in the revenue requirement and cost of capital portions of SPPC's case. The agreement, which has been approved by the PUCN, includes the following provisions:

- SPPC was allowed to recover a $40 million increase in annual rates.
- SPPC was allowed a Return on Equity (ROE) of 10.25%, and an overall Rate of Return (ROR) of 9.26%, an improvement over SPPC's previous ROE and ROR, which were 10.17% and 8.61%, respectively. SPPC had sought an ROE of 12.4% and ROR of 10.03%.
- The agreement accepted SPPC's requested accounting treatment as filed in its application for purposes of recording revenues, expenses and assets with the following exception. Accounting issues common to SPPC's general rate case and NPC's general rate case that was decided by the PUCN on March 26, 2004, in Docket No. 03-10001, are treated as set forth in the PUCN's Order on NPC's general rate case, except for merger costs. The accounting treatment for merger costs and goodwill established in the NPC decision will apply to the recovery of these costs by SPPC, except that SPPC will include in rates 100% of the costs as filed until recovery is reset by the PUCN in SPPC's next general rate application.
- Required SPPC to file a set of recommended quality of service and customer service measurements to be used in future general rate case proceedings. On July 1, 2004, SPPC and NPC jointly filed with the PUCN their recommended quality of service and customer service measurements. The PUCN opened up an investigatory docket to adjudicate the issues.

The parties also reached a stipulated agreement that resolved the rate design issues in the case.

Investments in the Piñon Pine generating facility were not addressed by the stipulation. SPPC had sought recovery of its investment of approximately $96 million ($90 million associated with the Nevada jurisdiction) for costs associated with this facility over an extended period (between 10 and 25 years). The recovery of these costs would be in addition to the $40 million annual increase provided for by the stipulation agreement.

NOTES TO FINANCIAL STATEMENTS (continued)

On May 27, 2004, the PUCN issued an order accepting the two stipulations, discussed above, and responding to SPPC's request for recovery of the Piñon investments. The PUCN permitted recovery of approximately $37 million (Nevada jurisdictional) of the costs plus a carrying charge to be amortized over 25 years and approximately $11 million (Nevada jurisdictional) of costs without a carrying charge to be amortized over 10 years. The PUCN order granted a $46.7 million increase to SPPC's general revenues.

As a result of the PUCN order, SPPC evaluated the Piñon Pine generating facility for impairment under the provisions of SFAS No. 90, "Regulated Enterprises—Accounting for Abandonments and Disallowances of Plant Costs". As a result of this evaluation, SPPC recognized an impairment loss of approximately $47 million in the second quarter of 2004. The impairment loss recognized consists of disallowed costs of approximately $43 million and an additional $4 million loss because the PUCN did not permit a carrying charge on $11 million of the costs to be recovered.

SPPC filed a petition for judicial review of the PUCN's Piñon Decision in the Second Judicial District Court of Nevada on June 8, 2004. The petition is based on existing resource planning statutes and regulations as they apply to the Piñon project. The Piñon project was approved by the PUCN in SPPC's 1992 Integrated Resource Plan as presented.

SPPC filed its opening brief in early October, and Answering and Reply briefs were filed in November and December, respectively. SPPC has asked for oral argument to occur in the first quarter of 2005. SPPC cannot predict the timing or outcome of a decision from this court.

Sierra Pacific Power Company 2004 Deferred Energy Case

On January 14, 2004, SPPC filed an application with the PUCN, as required by law, seeking to clear deferred balances for purchased fuel and power costs accumulated between December 1, 2002, and November 30, 2003. The Application requested a deviation from regulation and historic practice and to put in place an asymmetric amortization of the deferred energy balance of approximately $42 million, which would result in recovery of $8 million effective July 2004; $17 million effective July 2005; and $17 million effective July 2006. The Application also requested a deviation from regulation in resetting the BTER. That methodology and its results would result in no change to the currently effective BTER.

On July 7, 2004, the PUCN ruled on the deferred energy case, and approved a full recovery of the fuel and purchased power costs. The PUCN order delayed the start of the deferred balance recovery until April 2005, which corresponds with the expected repayment of previous deferred balances. The PUCN also ordered SPPC to implement a higher BTER rate (the rate paid for going forward energy purchases) than that requested by SPPC. The higher BTER rate represents an overall increase of 4.4% in electric rates for SPPC and became effective July 15, 2004.

Sierra Pacific Power Company 2003 Deferred Energy Case

On January 14, 2003, SPPC filed an application with the PUCN, as required by law, seeking to clear deferred balances for purchased fuel and power costs accumulated between December 1, 2001, and November 30, 2002. The application sought to establish a rate to clear accumulated purchased fuel and power costs of $15.4 million and spread the cost recovery over a period of not more than three years. It also sought to recalculate the rate to reflect anticipated ongoing purchased fuel and power costs. The total rate increase request amounted to 0.01%. The interveners' testimony was received April 25, 2003, and included proposed disallowances from $34 million to $76 million. Prior to the hearing that was scheduled to begin on May 12, 2003, the parties negotiated a settlement agreement. The agreement included the following provisions:

- A reduction in the current deferred energy balance of $45 million leaving a balance payable to customers of approximately $29.6 million.
- A two-year amortization of the amount payable returning one third of the balance in the first year (approximately $9.9 million), and two thirds of the balance the second year (approximately $19.7 million).
- Discontinue carrying charges on deferred energy balances that SPPC is already collecting from customers and on the $29.6 million amount payable as a result of the agreement.
- Maintain the currently effective Base Tariff Energy Rate.
- SPPC maintains the rights to claim the cost of terminated energy contracts in future deferred filings.
- Parties agreed that with the $45 million reduction the remaining costs for purchasing fuel and power during the test year were prudently incurred and are just and reasonable.
- SPPC and the BCP agreed to file a motion to dismiss the civil lawsuits filed in relation to the 2002 SPPC deferred energy case.

The agreement was approved by the PUCN at the agenda meeting held on May 19, 2003, and the new rates went into effect on June 1, 2003.

Sierra Pacific Power Company 2002 Deferred Energy Case

On February 1, 2002, SPPC filed an application with the PUCN, as required by law, seeking to clear deferred balances for purchased fuel and power costs accumulated between March 1, 2001 and November 30, 2001. The application sought to establish a DEAA rate to clear accumulated purchased fuel and power costs of $205 million and spread the cost recovery over a period of not more than three years. It also sought to recalculate the BTER to reflect anticipated ongoing purchased fuel and power costs.

On May 28, 2002, the PUCN issued its decision on the deferred energy application, allowing SPPC three years to collect $150 million but disallowing $53 million of deferred purchased fuel and power costs and $2 million in carrying charges.

On August 22, 2002, SPPC filed a lawsuit in the First District Court of Nevada seeking to reverse portions of the decision of the PUCN denying the recovery of deferred energy costs incurred by SPPC on behalf of its customers in 2001 on the grounds that such power costs were not prudently incurred. As part of the settlement agreement reached in connection with SPPC's 2003 deferred energy case, SPPC agreed to dismiss the lawsuit in May 2003.

SPPC Natural Gas Distribution 2004 Annual Purchased Gas Cost Adjustment

On May 14, 2004, SPPC filed its annual application for Purchased Gas Cost Adjustment for its natural gas local distribution company. In the application, SPPC asked for an increase of $0.09456 per therm to its Base Purchased Gas Rate to recover its expected going forward gas costs. SPPC also requested that $0.02857 per therm be added to the Balancing Account Adjustment (BAA) rate to amortize an approximate $3.9 million balance of deferred gas costs, which were accumulated during the accounting period. Combined with the simultaneous expiration of past BAA charges, the new BAA rate would be $0.03869 per therm less than the current BAA rate. Overall, this request would result in a rate increase of approximately 5%.

The parties agreed to a stipulation, which recommended the PUCN approve the requested rates and the PUCN issued an order approving the rate increase on November 8, 2004.

SPPC Natural Gas Distribution 2003 Purchased Gas Cost Adjustment

On May 15, 2003, SPPC filed its annual application for Purchased Gas Cost Adjustment for its natural gas local distribution company. In the application, SPPC asked for an increase of $0.02524 per therm to its Base Purchased Gas Rate (BPGR) and a BAA credit to customers of $0.04833 per therm to be amortized over two years. This request would have resulted in a decrease of approximately 5% in customer rates.

SPPC, the PUCN Staff, and the BCP agreed upon a Stipulation, which was approved by the PUCN on October 1, 2003.

As a result of the stipulation, overall, rates for SPPC's natural gas customers decreased by approximately 3%. The Parties agreed that the new BAA would be amortized over two years with 67% of the balance recovered in the first year, and 33% of the balance recovered in the second year. The BAA rate for the first year will be a credit of $0.06448 per therm. The BAA rate for the second year will be a credit of $0.03176 per therm. A BPGR of $0.066375 per therm was approved, an increase from the previous BPGR of $0.05316 per therm. The new rates were implemented November 1, 2003.

SPPC Natural Gas Distribution 2002 Purchased Gas Cost Adjustment

On July 1, 2002, SPPC filed a Purchased Gas Cost Adjustment application for its natural gas local distribution company. In the application, SPPC has asked for a reduction of $0.05421 to its BPGR and an increase in its BAA charge by the same amount. This request would result in no change to revenues or customer rates.

On December 23, 2002, the PUCN voted to decrease rates for SPPC's natural gas customers by approximately 3% ($3.2 million plus applicable carrying charges). The new rates were implemented January 1, 2003.

California Electric Matters (SPPC)

Sierra Pacific Power Company 2004 Energy Cost Adjustment Clause

On May 1, 2004, SPPC filed its annual Energy Cost Adjustment Clause (ECAC) in California. The filing updated its estimated fuel and purchase power costs for its California customers and sought to recover or refund any deferred amounts projected through September 30, 2004. The filing requests $8.3 million or a 14.8% overall increase consisting of $3.9 million increase in the base rate and $4.4 million for the projected balance. Pre-hearing conferences were held on July 14 and August 4, 2004. On August 16, 2004, the CPUC Office of Ratepayer Advocates issued a report recommending the CPUC accept SPPC's ECAC proposal with a minor change to the rate design calculations. SPPC accepted the change and the resulting decrease to the request of $13,000. On October 4, 2004, the CPUC issued a draft order recommending approval of SPPC's adjusted ECAC proposal. No hearings were necessary and on November 19, 2004, the CPUC approved SPPC's adjusted request and the increase became effective December 1, 2004.

Rate Stabilization Plan

On June 29, 2001, SPPC filed with the CPUC a Rate Stabilization Plan, which included two phases. Phase One, which was also filed June 29, 2001, was an emergency electric rate increase of $10.2 million annually or 26%. If granted, the typical residential monthly electric bill for a customer using 650 kilowatt-hours would have increased from approximately $47.12 to $60.12. On July 17, 2002, the CPUC approved the requested 2-cent per kilowatt-hour surcharge, subject to refund and interest pending the outcome of Phase Two. The increase of $10 million or 26% is applicable to all customers except those eligible for low-income and medical-needs rates and went into effect July 18, 2002.

Phase Two of the Rate Stabilization Plan was filed with the CPUC on April 1, 2002, and included a general rate case and requests the CPUC to reinstate the ECAC, which would allow SPPC to file for annual rate adjustments to reflect its actual costs for wholesale energy supplies. This request was for an additional overall increase in revenues of 17.1%, or $8.9 million annually.

On January 8, 2004, the CPUC issued Decision No. 04-01-027, which approved a settlement agreement that included an increase of $3.02 million or 5.8%, adopted a rate design methodology and re-instituted the ECAC mechanism. The rate increase was effective January 16, 2004.

FERC Matters

Sierra Pacific Power Company 2004 Transmission Rate Case

On October 1, 2004, the Utilities filed with the FERC revised rates for transmission service offered by SPPC under Docket No. ER05-14. The purpose of the filing was to update rates to reflect recent transmission additions and to improve rate design. The participants in the proceeding reached a settlement in principle of all issues on February 15, 2005. The parties will file a Settlement Agreement with the FERC and expect FERC to issue an Order approving settlement in the second quarter of 2005.

NOTES TO FINANCIAL STATEMENTS (continued)

Nevada Power Company 2003 Transmission Rate Case

On September 11, 2003, the Utilities filed with the FERC revised rates for transmission service offered by NPC under Docket No. ER03-1328. The purpose of the filing is to update rates to reflect recent transmission additions and to improve rate design. On November 7, 2003, FERC accepted the revised tariff sheets, made rates effective on November 10, 2003, subject to refund, and established hearing procedures. The active participants in the proceeding reached a settlement in principle of all issues. The Certification of Uncontested Offer of Settlement was issued on June 14, 2004. The FERC issued an Order approving the uncontested settlement on July 8, 2004. Refunds were issued within thirty days as required by FERC.

NOTE 4. INVESTMENTS IN SUBSIDIARIES AND OTHER PROPERTY

Investments in subsidiaries and other property consisted of (dollars in thousands):

Sierra Pacific Resources

December 31,	2004	2003
Investment in Tuscarora Gas Transmission Company	**$31,019**	$31,016
Cash Value-Life Insurance	**12,967**	13,065
Non-utility property of NEICO	**5,486**	3,474
NVPCT-I & NVPCT-III	**5,841**	5,841
Southern Service Center Property	**—**	12,143
Decatur/Gilmore/Cheyenne/Centennial	**6,515**	—
Other non-utility property	**2,768**	7,591
	$64,596	$73,130

Nevada Power

December 31,	2004	2003
Cash Value-Life Insurance	**$12,967**	$13,065
Non-utility property of NEICO	**5,486**	3,474
NVPCT-I & NVPCT-III	**5,841**	5,841
Southern Service Center Property	**—**	12,143
Decatur/Gilmore/Cheyenne/Centennial	**6,515**	—
Non-utility property	**—**	1,789
	$30,809	$36,312

Sierra Pacific Power

December 31,	2004	2003
Non-utility property	**$999**	$916

NOTE 5. JOINTLY OWNED FACILITIES

At December 31, 2004, NPC and SPPC owned the following undivided interests in jointly owned electric utility facilities:

Joint Facility	% Owned	Plant-in-Service	Accumulated Depreciation	Net Plant-in-Service	Construction Work in Progress
NPC					
Navajo Facility	11.3	$243,033	$114,072	$128,961	$4,322
Mohave Facility	14.0	86,262	48,236	38,026	2,225
Reid Gardner No. 4	32.2	123,727	72,866	50,861	1,359
Total NPC		$453,022	$235,174	$217,848	$7,906
SPPC					
Valmy Facility	50.0	$287,266	$149,722	$137,544	$ 574

The amounts for Navajo and Mohave include NPC's share of transmission systems and general plant equipment and, in the case of Navajo, NPC's share of the jointly owned railroad which delivers coal to the plant. Each participant provides its own financing for all of these jointly owned facilities. NPC's share of operating expenses for these facilities is included in the corresponding operating expenses in its Consolidated Statements of Operations.

NPC's ownership interest in Mohave comprises approximately 10% of NPC's peak generation capacity. Southern California Edison (SCE) is the operating partner of Mohave. On May 17, 2002, SCE filed with the CPUC an application to address the future disposition of SCE's share of Mohave. Mohave obtains all of its coal supply from a mine in northeast Arizona on lands of the Navajo Nation and the Hopi Tribe (the Tribes). This coal is delivered from the mine to Mohave by means of a coal slurry pipeline which requires water that is obtained from groundwater wells located on lands of the Tribes in the mine vicinity.

Due to the lack of progress in negotiations with the Tribes and other parties to resolve several coal and water supply issues, SCE's application states that it appears that it probably will not be possible for SCE to extend Mohave's operations beyond 2005. Due to the uncertainty over a post-2005 coal supply, SCE and the other Mohave co-owners have been prevented from commencing the installation of extensive pollution control equipment that must be put in place if Mohave's operations are extended past 2005.

Because of the coal and water supply issues at Mohave, NPC is preparing for the shutdown of the facility by the end of 2005. NPC's IRP accepted by the PUCN in November 2003, assumes the Plant will be unavailable after December 31, 2005. In addition, in its General Rate Case filed on October 1, 2003, NPC requested that the PUCN authorize a higher depreciation rate be applied to Mohave in order to recover the remaining book value to a regulatory asset account to be amortized over a period as determined by the PUCN. While the PUCN did not approve higher depreciation rates, they did authorize the use of a regulatory asset to accumulate the costs and savings associated with Mohave in the event of its shutdown with recovery of any accumulated costs in a future rate case proceeding. However, if NPC is unsuccessful in obtaining recovery of the regulatory asset in a future rate case and the asset is deemed impaired in accordance with SFAS No. 90, Accounting for Abandonments and Disallowances of Plant Costs, there could be a material effect on NPC's and SPR's financial position, results of operations, and future cash inflows. If SCE determines that the plant can be modified to burn alternative fuels we anticipate the shutdown to be temporary to install the required pollution control equipment.

SPPC and Idaho Power Company each own an undivided 50% interest in the Valmy generating station, with each company being responsible for financing its share of capital and operating costs. SPPC is the operator of the plant for both parties. SPPC's share of direct operation and maintenance expenses for Valmy is included in its accompanying Consolidated Statements of Operations.

NOTE 6. SHORT-TERM BORROWINGS

Nevada Power Company

Accounts Receivable Facility

On May 4, 2004, NPC delivered a notice of termination of its accounts receivable facility in connection with the establishment of its new revolving credit facility. The termination was effective on May 19, 2004.

Sierra Pacific Power Company

Revolving Credit Facility

On October 22, 2004, SPPC terminated its $50 million long-term revolving credit facility, which had been established on May 4, 2004, and replaced it with a three-year revolving credit facility of $75 million. $25 million of the $75 million credit facility is short-term until SPPC receives long-term debt authority from the PUCN for the additional $25 million. SPPC has not yet determined whether it will seek such long-term authority.

Short-Term Financing

On January 30, 2004, SPPC issued its General and Refunding Mortgage Note, Series G, due March 31, 2004, in the maximum principal amount of $22 million under a revolving Credit Agreement with Lehman Commercial Paper Inc. Borrowings under the Series G Note were to be used to provide back-up liquidity for SPPC during its 2003-2004 winter peak. This credit facility was never used prior to its maturity on March 31, 2004.

On December 22, 2003, SPPC issued and sold its $25 million General and Refunding Mortgage Notes, Series F, due March 31, 2004 in order to provide additional liquidity for SPPC's fuel and power purchases during its 2003-2004 winter peak. The terms of the Series F Notes were substantially similar to SPPC's Term Loan Facility in place during that time. The notes were paid off in March 2004.

Accounts Receivable Facility

On May 4, 2004, SPPC delivered a notice of termination of its accounts receivable facility in connection with the establishment of its new revolving credit facility. The termination was effective on May 19, 2004.

NOTE 7. LONG-TERM DEBT

As of December 31, 2004 NPC's, SPPC's and SPR's aggregate annual amount of maturities for long-term debt (including obligations related to capital leases) for the next five years is shown below (dollars in thousands):

	NPC	SPPC	SPR Holding Co. and Other Subs	SPR Consolidated
2005	$ 6,091	$ 2,400	$ —	$ 8,491
2006	6,509	52,400	—	58,909
2007	5,949	2,400	240,218	248,567
2008	7,066	322,400	—	329,466
2009	272,510	600	—	273,110
	298,125	380,200	240,218	918,543
Thereafter	1,993,505	617,250	635,000 (1)	3,245,755
	2,291,630	997,450	875,218	4,164,298
Unamortized Discount	(9,849)	(741)	(6,014)	(16,604)
Total	$2,281,781	$996,709	$869,204	$4,147,694

(1) SPR's "Thereafter" amount of $635 million includes $300 million, which is the total amount of the 7.25% Convertible Notes due at maturity. This differs from the carrying value of $242,078 million included in the balance sheet amount of long-term debt, which is being accreted to face value using the effective interest method.

NOTES TO FINANCIAL STATEMENTS (continued)

The preceding table includes obligations related to capital lease obligations discussed under lease commitments within this note.

Substantially all utility plant is subject to the liens of NPC's and SPPC's indentures under which their First Mortgage bonds and General and Refunding Mortgage bonds are issued.

Nevada Power Company

General and Refunding Mortgage Notes, Series L

On November 16, 2004, NPC issued and sold $250 million of its 5⅞% General and Refunding Mortgage Notes, Series L, due January 15, 2015. The Series L Notes were issued with registration rights. The proceeds of the issuance were used to repay $150 million outstanding under NPC's $350 million revolving credit facility expiring October 8, 2007. Remaining proceeds will be used to pay costs in connection with the acquisition and construction of the Chuck Lenzie Generating Station and for general corporate purposes.

The Series L Notes, similar to NPC's Series E, Series G and Series I Notes, and Series H Bond, limit the amount of payments in respect of common stock dividends that NPC may pay to SPR. This limitation is discussed in Note 9, Dividend Restrictions.

The terms of the Series L Notes, as with the Series E Notes, Series G Notes, Series I Notes, and Series H Bond, also restrict NPC from incurring any additional indebtedness unless:

1. at the time the debt is incurred, the ratio of consolidated cash flow to fixed charges for NPC's most recently ended four quarter period on a pro forma basis is at least 2.0 to 1, or
2. the debt incurred is specifically permitted under the terms of the applicable Notes or Bond, which permits the incurrence of certain credit facility or letter of credit indebtedness, obligations incurred to finance property construction or improvement, indebtedness incurred to refinance existing indebtedness, certain intercompany indebtedness, hedging obligations, indebtedness incurred to support bid, performance or surety bonds, and certain letters of credit issued to support NPC's obligations with respect to energy suppliers, or
3. in the case of the Series G Notes, Series I Notes and Series L Notes, and the Series H Bond, indebtedness incurred to finance capital expenditures pursuant to NPC's 2003 Integrated Resource Plan.

If NPC's Series E Notes, Series G Notes, Series I Notes, Series L Notes or Series H Bond are upgraded to investment grade by both Moody's Investor Service, Inc. (Moody's) and Standard & Poor's Rating Group, Inc. (S&P), these restrictions will be suspended and will no longer be in effect so long as the applicable series of Notes or the Bond remains investment grade.

Among other things, the Series E Notes, Series G Notes, Series I Notes, Series L Notes, and Series H Bond also contain restrictions on liens (other than permitted liens, which include liens to secure certain permitted debt) and certain sale and leaseback transactions. In the event of a change of control of NPC, the holders of these securities are entitled to require that NPC repurchase their securities for a cash payment equal to 101% of the aggregate principal amount plus accrued and unpaid interest.

Revolving Credit Facility

On October 8, 2004, NPC entered into a $250 million Credit Agreement with Union Bank of California, N.A., as Administrative Agent, to finance the purchase price of the Chuck Lenzie Generating Station (the Facility), to pay fees, costs and expenses incurred by NPC in connection with the purchase and construction of the Facility and for general corporate purposes. On October 22, 2004, NPC amended and restated the Credit Agreement to increase the total size of the revolving credit facility to $350 million, concurrently with its termination of its $100 million Credit Facility, which was established on May 4, 2004.

The new revolving credit facility, which is secured by NPC's $350 million General and Refunding Mortgage Bond, Series K, will expire October 8, 2007. The rate for outstanding loans and/or letters of credit under revolving credit facility will be at either an alternate base rate or a Eurodollar rate plus a margin that varies based upon NPC's credit rating by S&P and Moody's. Currently, NPC's alternate base rate margin is 1.00% and its Eurodollar margin is 2.00%.

On October 8, 2004, NPC borrowed $150 million under the revolving credit facility to pay part of the $182 million purchase price for the Facility. The remainder of the purchase price was funded with available cash. This $150 million outstanding balance was paid off concurrently with receiving the proceeds of the General and Refunding Mortgage Notes, Series L, issued on November 16, 2004.

The NPC Credit Agreement contains two financial maintenance covenants. The first requires that NPC maintain a ratio of consolidated indebtedness to consolidated capital, determined as of the last day of each fiscal quarter, not to exceed 0.68 to 1. The second requires that NPC maintain a ratio of consolidated cash flow to consolidated interest expense, determined as of the last day of each fiscal quarter for the period of four consecutive fiscal quarters, not to be less than 2.0 to 1.

The NPC Credit Agreement, similar to NPC's Series E Notes, Series G Notes, Series I Notes, Series L Notes and Series H Bond, limits the amount of payments in respect of common stock dividends that NPC may pay to SPR. This limitation is discussed in Note 9, Dividend Restrictions.

The Credit Agreement also contains a restriction on NPC's ability to incur additional indebtedness which is similar to the restriction discussed above for NPC's Series L Notes.

Among other things, the NPC Credit Agreement also contains restrictions on liens (other than permitted liens, which include liens to secure certain permitted debt) and certain sale and leaseback transactions. There are also limitations on certain fundamental structural changes to NPC and limitations on the disposition of property.

The NPC Credit Agreement provides for certain events of default including any of the following events: NPC fails to make payments of principal or interest under the Credit Agreement, NPC fails to comply with certain agreements included in the Credit Agreement, NPC files for bankruptcy, or a change of control occurs. The Credit Agreement also provides for an event of default if a judgment of $15 million or more is entered against NPC and such judgment is not vacated, discharged, stayed or bonded pending appeal within 60 days. Since the Credit Agreement also prohibits the creation or existence of any liens on NPC's properties except for liens specifically permitted under the Credit Agreement, if a judgment lien is filed against NPC, the filing of the lien will trigger an event of default under the Credit Agreement. The Credit Agreement also provides for an event of default if NPC defaults in the payment of principal, interest or premium beyond the applicable grace period under any mortgage, indenture or other security instrument, relating to debt in excess of $15 million.

Upon an event of default, the Administrative Agent under the NPC Credit Agreement may, upon request of more than 50% of the lenders under the Credit Agreement, declare all amounts due under the Credit Agreement immediately due and payable. Since NPC's obligations under the Credit Agreement are secured by its General and Refunding Mortgage Bond, if NPC fails to repay all amounts due upon an acceleration of the Credit Agreement within three business days, such failure will be deemed a default in the payment of principal and will trigger an event of default under the NPC General and Refunding Mortgage Indenture that would be applicable to all securities issued under the NPC General and Refunding Mortgage Indenture.

$100 Million Revolving Credit Facility

On May 4, 2004, NPC established a $100 million Revolving Credit Facility with a maturity date of May 4, 2009. Borrowings under this facility were secured by NPC's General and Refunding Mortgage Bond, Series J, due 2009. On June 30, 2004, NPC drew upon this new Revolving Credit Facility for $10 million to meet necessary liquidity needs for ongoing operations. NPC repaid its outstanding borrowings on August 4, 2004.

Concurrent with the amendment and restatement of the new $350 million revolving credit facility, discussed above, this $100 million facility was terminated on October 22, 2004. There were no amounts outstanding under this facility at the time of termination.

General and Refunding Mortgage Notes, Series I

On April 7, 2004, NPC issued and sold $130 million of its 6½% General and Refunding Mortgage Notes, Series I, due April 15, 2012. The Series I Notes, which were issued with registration rights, were exchanged for registered notes in October 2004. The proceeds of the issuance were used to pay off $130 million aggregate principal amount of NPC's 6.20% Series B, Senior Notes due April 15, 2004. The Series I Notes contain terms and provisions substantially similar to those in the Series L Notes, discussed above.

General and Refunding Mortgage Bond, Series H

On December 4, 2003, NPC issued its General and Refunding Mortgage Bond, Series H, in the principal amount of $235 million, to an escrow agent in accordance with the Enron stay order. As long as the bonds remain in escrow, they will not be recorded in Long-Term Debt on NPC's balance sheet. See Note 14, Commitments and Contingencies,for more information regarding the Enron litigation.

On February 10, 2004, in accordance with the terms of the Enron stay order, NPC deposited approximately $24 million into the escrow account which amount was deducted from the outstanding principal amount of the Series H Bond. The terms of the Series H Bond are substantially similar to NPC's Series L Notes, discussed above. Subsequently, on April 16, 2004 , NPC deposited an additional $25 million to the escrow account for a total of $49 million, reducing the principal amount of the bond held in escrow to approximately $186 million.

General and Refunding Mortgage Notes, Series G

On August 13, 2003, NPC issued and sold $350 million of its 9% General and Refunding Mortgage Notes, Series G, due 2013. The Series G Notes, which were issued with registration rights, were exchanged for registered notes in June 2004. The proceeds of the issuance were used to pay off $210 million of its unsecured 6% Notes due September 15, 2003 and $140 million of its General and Refunding Mortgage Notes, Floating Rate, Series B, due October 15, 2003 and for general corporate purposes. The Series G Notes will mature August 15, 2013. The terms of the Series G Notes are substantially similar to NPC's Series L Notes, discussed earlier.

General and Refunding Mortgage Notes, Series E

On October 29, 2002, NPC issued and sold $250 million of its 10⅞% General and Refunding Mortgage Notes, Series E, due 2009. The Series E Notes, which were issued with registration rights, were exchanged for registered notes in January 2003. The $235.6 million net proceeds of the issuance were used to pay off NPC's $200 million credit facility and for general corporate purposes. The Series E Notes will mature October 15, 2009. With some exceptions, the terms of the Series E Notes are substantially similar to NPC's Series L Notes, discussed earlier. Where there are exceptions they are noted in the Series L Notes discussion.

Preferred Trust Securities

NVP Capital I Trust

On April 2, 1997, NVP Capital I (Trust), a wholly owned subsidiary of NPC, issued 4,754,860, 8.2% preferred trust securities (QUIPS) at $25 per security. NPC owns all of the Series A common securities, 147,058 shares issued by the Trust for $3.7 million. The QUIPS and the common securities represent undivided beneficial ownership interests in the assets of the Trust, a statutory business trust formed under the laws of the state of Delaware. The existence of the Trust is for the sole purpose of issuing the QUIPS and the common securities and using the proceeds thereof to purchase from NPC its 8.2% Junior Subordinated Deferrable Interest Debentures (QUIDS)

NOTES TO FINANCIAL STATEMENTS (continued)

due March 31, 2037, extendible to March 31, 2046, under certain conditions, in a principal amount of $122.6 million. FIN 46(R) requires that the Trust be deconsolidated. As such, the Trust Preferred Securities are no longer consolidated with NPC and the Junior Subordinated Debt is now presented as Long-Term Debt.

Holders of the Series A QUIPS are entitled to receive preferential cumulative cash distributions accruing from the date of original issuance and payable quarterly on the last day of March, June, September and December of each year. Interest payments made by NPC in respect of the QUIDS are sufficient to provide the trust with funds to pay the required cash distribution on the QUIPS and the common securities of the trust. The Series A QUIPS are subject to mandatory redemption, in whole or in part, upon repayment of the Series A QUIDS at maturity or their earlier redemption in an amount equal to the amount of related Series A QUIDS maturing or being redeemed. The QUIPS are redeemable at $25 per preferred security plus accumulated and unpaid distributions thereon to the date of redemption.

NVP Capital III Trust

In October 1998, NVP Capital III (Trust), a wholly owned subsidiary of NPC, issued 2,800,000, 7.75% Cumulative Trust Issued Preferred Securities (TIPS) at $25 per security. NPC owns the entire common securities, 86,598 shares issued by the Trust for $2.2 million. The TIPS and the common securities represent undivided beneficial ownership interests in the assets of the Trust, a statutory business trust formed under the laws of the state of Delaware. The existence of the Trust is for the sole purpose of issuing the TIPS and the common securities and using the proceeds thereof to purchase from NPC its 7.75% Junior Subordinated Deferrable Interest Debentures due September 30, 2038, extendible to September 30, 2047, under certain conditions, in a principal amount of $72.2 million. FIN 46(R) requires that the Trust be deconsolidated. As such, the Trust Preferred Securities are no longer consolidated with NPC and the Junior Subordinated Debt is now presented as Long-Term Debt.

Holders of the TIPS are entitled to receive preferential cumulative cash distributions accruing from the date of original issuance and payable quarterly on the last day of March, June, September and December of each year. Interest payments by NPC in respect of the Junior Subordinated Deferrable Interest Debentures are sufficient to provide the trust with funds to pay the required cash distributions on the TIPS and the common securities of the trust. The TIPS are subject to mandatory redemption, in whole or in part, upon repayment of the deferrable interest debentures at maturity or their earlier redemption in an amount equal to the amount of related deferrable interest debentures maturing or being redeemed. The TIPS are redeemable at $25 per preferred security plus accumulated and unpaid distributions thereon to the date of redemption.

Sierra Pacific Power Company

Revolving Credit Facility

On October 22, 2004, SPPC entered into a $75 million credit agreement, which is secured by SPPC's $75 million General and Refunding Mortgage Bond, Series L, will expire on October 22, 2007. The rate for outstanding loans and/or letters of credit under revolving credit facility will be at either an alternate base rate or a Eurodollar rate plus a margin that varies based upon SPPC's credit rating by S&P and Moody's. Currently, SPPC's alternate base rate margin is 1.00% and its Eurodollar margin is 2.00%. SPPC has not borrowed any amounts under this revolving credit facility.

Upon the effectiveness of the credit agreement, SPPC terminated its $50 million revolving credit facility, which it entered into on May 4, 2004. No amounts were outstanding under this facility at the time of termination.

The SPPC credit agreement contains two financial maintenance covenants. The first requires that SPPC maintain a ratio of consolidated indebtedness to consolidated capital, determined as of the last day of each fiscal quarter, not to exceed 0.68 to 1. The second requires that SPPC maintain a ratio of consolidated cash flow to consolidated interest expense, determined as of the last day of each fiscal quarter for the period of four consecutive fiscal quarters, not to be less than 2.0 to 1.

Due to a negative pledge obligation in SPPC's Series E Bond, which was issued to an escrow agent to secure Enron's judgment against SPPC (see Note 14, Commitments and Contingencies), SPPC amended its Series E Bond to include these two financial maintenance covenants. Although the judgment was vacated in a decision handed down on October 10, 2004 by the U.S. District Court for the Southern District of New York, SPPC's Series E Bond will continue to remain in escrow through the pendency of all remands and appeals pursuant to a stipulation and agreement previously entered into among NPC, SPPC and Enron.

The Credit Agreement, similar to SPPC's Series H Notes and Series E Bond, limits the amount of payments in respect of common stock dividends that SPPC may pay to SPR. This limitation is discussed in Note 9, Dividend Restrictions.

The Credit Agreement also contains a restriction on SPPC's ability to incur additional indebtedness which is similar to the restriction discussed below for SPPC's Series H Notes and Series E Bond.

Among other things, the SPPC Credit Agreement also contains restrictions on liens (other than permitted liens, which include liens to secure certain permitted debt) and certain sale and leaseback transactions. There are also limitations on certain fundamental structural changes to SPPC and limitations on the disposition of property.

The SPPC Credit Agreement provides for certain events of default including any of the following events: SPPC fails to make payments of principal or interest under the Credit Agreement, SPPC fails to comply with certain agreements included in the Credit Agreement, SPPC files for bankruptcy, or a change of control occurs. The Credit Agreement also provides for an event of default if a judgment of $15 million or more is entered against SPPC and such judgment is not vacated, discharged, stayed or bonded pending appeal within 60 days. Since, the Credit Agreement also prohibits the creation or existence of any liens on SPPC's properties except for liens specifically permitted under the Credit Agreement, if a judgment lien is filed against SPPC, the filing of the lien will trigger an event of default under the Credit Agreement. The Credit Agreement also provides for an event of default if SPPC defaults in the payment of principal, interest or premium beyond the applicable grace period under any mortgage, indenture or other security instrument, relating to debt in excess of $15 million.

Upon an event of default, the Administrative Agent under the SPPC Credit Agreement may, upon request of more than 50% of the lenders under the Credit Agreement, declare all amounts due under the Credit Agreement immediately due and payable. Since SPPC's obligations under the Credit Agreement are secured by its General and Refunding Mortgage Bond, if SPPC fails to repay all amounts due upon an acceleration of the Credit Agreement within three business days, such failure will be deemed a default in the payment of principal and will trigger an event of default under the SPPC General and Refunding Mortgage Indenture that would be applicable to all securities issued under the SPPC General and Refunding Mortgage Indenture.

$50 Million Revolving Credit Facility

On May 4, 2004, SPPC established a $50 million Revolving Credit Facility with a maturity date of May 4, 2008. Borrowings under this facility were evidenced on SPPC's General and Refunding Mortgage Bond, Series K, due 2008.

Concurrent with the establishment of its new $75 million revolving credit facility, discussed above, this existing facility was terminated on October 22, 2004. No amounts were outstanding under this facility at the time of termination.

Water Facilities Refunding Revenue Bonds

On May 3, 2004, SPPC's $80 million Washoe County, Nevada, Water Facilities Refunding Revenue Bonds, Series 2001, were successfully remarketed. The interest rate on the bonds was adjusted from their prior one year 7.50% term rate to a 5.0% term rate for the period of May 3, 2004 up to and including July 1, 2009. The bonds will be subject to remarketing on July 1, 2009. In the event that the bonds cannot be successfully remarketed on that date, SPPC will be required to purchase the outstanding bonds at a price of 100% of principal amount plus accrued interest. From May 3, 2004 up to and including July 1, 2009, SPPC's payment and purchase obligations in respect of the bonds are secured by SPPC's $80 million General and Refunding Mortgage Note, Series J, due 2009.

General and Refunding Mortgage Notes, Series H

On April 16, 2004, SPPC issued and sold $100 million of its 6¼% General and Refunding Mortgage Notes, Series H, due April 15, 2012. The Series H Notes, which were issued with registration rights, were exchanged for registered notes in October 2004. The proceeds of the issuance along with operating cash were used to substantially pay off SPPC's 10.5% Term Loan Facility, due October 2005.

The Series H Notes, similar to SPPC's Series E Bond, limit the amount of payments in respect of common stock dividends that SPPC may pay to SPR. This limitation is discussed in Note 9, Dividend Restrictions.

The terms of the Series H Notes, as with the Series E Bond, also restrict SPPC from incurring any additional indebtedness unless:

(1) at the time the debt is incurred, the ratio of consolidated cash flow to fixed charges for SPPC's most recently ended four quarter period on a pro forma basis is at least 2.0 to 1, or

(2) the debt incurred is specifically permitted under the terms of the Series H Notes, which permits the incurrence of certain credit facility or letter of credit indebtedness, obligations incurred to finance property construction or improvement, indebtedness incurred to refinance existing indebtedness, certain intercompany indebtedness, hedging obligations, indebtedness incurred to support bid, performance or surety bonds, and certain letters of credit issued to support SPPC's obligations with respect to energy suppliers, or

(3) indebtedness incurred to finance capital expenditures pursuant to SPPC's 2004 Integrated Resource Plan.

If SPPC's Series H Notes are upgraded to investment grade by both Moody's and S&P, these restrictions will be suspended and will no longer be in effect so long as the Series H Notes remain investment grade.

Among other things, the Series H Notes also contain restrictions on liens (other than permitted liens, which include liens to secure certain permitted debt) and certain sale and leaseback transactions. In the event of a change of control of SPPC, the holders of these securities are entitled to require that SPPC repurchase their securities for a cash payment equal to 101% of the aggregate principal amount plus accrued and unpaid interest.

General and Refunding Mortgage Bond, Series E

On December 4, 2003, SPPC issued its General and Refunding Mortgage Bond, Series E, in the principal amount of $103 million, to an escrow agent in accordance with the Enron stay order. As long as the bonds remain in escrow, they will not be recorded in long-term debt on SPPC's balance sheet. See Note 14, Commitments and Contingencies, for more information regarding the Enron litigation.

On February 10, 2004, in accordance with the terms of the Enron stay order, SPPC deposited approximately $11 million into the escrow account which amount was deducted from the outstanding principal amount of the Series E Bond, reducing the principal amount of the bonds to approximately $92 million. The terms of the Series E Bond are substantially similar to SPPC's Series H Notes, discussed above.

NOTES TO FINANCIAL STATEMENTS (continued)

Term Loan Agreement

On October 30, 2002, SPPC entered into a $100 million Term Loan Agreement with several lenders and Lehman Commercial Paper Inc., as Administrative Agent. The net proceeds of $97 million from the Term Loan Facility, along with available cash, were used to pay off SPPC's $150 million credit facility, which was secured by SPPC's Series B General and Refunding Mortgage Bond. The Term Loan Facility, which is secured by SPPC's $100 million Series C General and Refunding Mortgage Bond, will expire October 31, 2005.

In April 2004 the Term Loan was paid off and the Term Loan Agreement was terminated.

Sierra Pacific Resources

SPR Senior Unsecured Notes

On March 19, 2004, SPR issued and sold $335 million 8⅝% Senior Unsecured Notes due March 15, 2014. The Senior Unsecured Notes, which were issued with registration rights, were exchanged for registered notes in October 2004. The proceeds of the issuance were used to fund the repurchase of approximately $174 million in principal amount of SPR's 8¾% Notes due 2005 at a price equal to approximately 107.225% of the principal amount thereof that were tendered pursuant to SPR's tender offer.

The balance of the net proceeds were used on May 21, 2004 to legally extinguish the approximately $126 million of remaining principal amount of SPR's 8¾% Notes due 2005 which were not tendered, and to pay associated interest and fees and expenses associated with the tender offer and the Notes offering. The total cost to extinguish the debt was approximately $23.7 million consisting of tender fees, interest costs and unamortized debt issuance costs.

The terms of the SPR Senior Notes restrict SPR and any of its Restricted Subsidiaries (NPC and SPPC) from incurring any additional indebtedness unless:

(1) at the time the debt is incurred, the ratio of consolidated cash flow to fixed charges for SPR's most recently ended four quarter period on a pro forma basis is at least 2.0 to 1, or

(2) the debt incurred is specifically permitted under the terms of the SPR Senior Notes, which permits the incurrence of certain credit facility or letter of credit indebtedness, obligations incurred to finance property construction or improvement, indebtedness incurred to refinance existing indebtedness, certain intercompany indebtedness, hedging obligations, indebtedness incurred to support bid, performance or surety bonds, and certain letters of credit supporting SPR's or any Restricted Subsidiary's obligations to energy suppliers, or

(3) the indebtedness is incurred to finance capital expenditures pursuant to NPC's 2003 Integrated Resource Plan and SPPC's 2004 Integrated Resource Plan.

If these Notes are upgraded to investment grade by both Moody's and S&P, these restrictions will be suspended and will no longer be in effect so long as the applicable series of Notes remains investment grade.

Among other things, the SPR Notes also contain restrictions on liens (other than permitted liens, which include liens to secure certain permitted debt) and certain sale and leaseback transactions. In the event of a change of control of SPR or any of its Restricted Subsidiaries, the holders of these securities are entitled to require that SPR repurchase their securities for a cash payment equal to 101% of the aggregate principal amount plus accrued and unpaid interest.

SPR Convertible Notes

On February 14, 2003, SPR issued and sold $300 million of its 7.25% Convertible Notes due 2010. Interest is payable semi-annually. At December 31, 2004 the carrying value of the Convertible Notes is approximately $242 million with an effective interest rate of 12.5%.

Approximately $53.4 million of the net proceeds from the sale of the notes were used to purchase U.S. government securities that were pledged to the trustee for the first five interest payments on the notes payable during the first two and one-half years. A portion of the remaining net proceeds of the notes were used to repurchase approximately $58.5 million of SPR's Floating Rate Notes due April 20, 2003. Of the remaining net proceeds, approximately $133 million were used to repay SPR's Floating Rate Notes due April 20, 2003, and the remaining proceeds were available for general corporate purposes. The Convertible Notes were issued with registration rights.

On August 11, 2003, SPR obtained shareholder approval to issue up to 42,736,920 additional shares of SPR's common stock in lieu of paying the cash payment component upon conversion of the Convertible Notes. Before SPR received shareholder approval, holders of the Convertible Notes were entitled to receive both shares of common stock and cash upon conversion on their notes. As a result of receiving shareholder approval, through the close of business on February 14, 2010, for each $1,000 principal amount of the Convertible Notes surrendered, SPR has the option to issue:

(1) 76.7073 shares of Common Stock plus an amount of cash equal to the then market value of 142.4564 shares of SPR Common Stock, subject to adjustment upon the occurrence of certain dilution events, or

(2) 219.1637 shares of SPR Common Stock, subject to adjustment upon the occurrence of certain dilution events.

If the noteholders present the Convertible Notes for conversion and SPR elects to convert the notes into stock and cash, the total amount of the cash payable on conversion would be approximately $428 million, at an assumed five-day average closing price of $10.02 per share (based upon the last reported sale price of SPR's common stock on February 28, 2005. The amount of cash payable on conversion of the Convertible Notes will increase as the average closing price of SPR's common stock increases. As a result of the shareholder approval discussed above, the conversion of the Convertible Notes may be fully satisfied by the issuance of stock at SPR's election. As such, the portion that previously would have been required to have been settled in cash has been reclassified as a long-term liability. See Note 10, Derivative and Hedging Activities for the effects of the Conversion option.

The Convertible Notes provide for the payment of dividends to the holders in an amount equal to any per share dividends on SPR common stock that would have been payable to the holders if the holders of the notes had converted their notes into shares of common stock at the applicable conversion rate on the record date for such dividend. See Note 17, Earnings Per Share for the effect on SPR's earnings per share calculations.

The indenture under which the Convertible Notes were issued does not contain any financial covenants or any restrictions on the payment of dividends, the repurchase of SPR's securities or the incurrence of indebtedness. The indenture does allow the holders of the Convertible Notes to require SPR to repurchase all or a portion of the holders' Convertible Notes upon a change of control. The indenture also provides for an event of default if SPR or any of its significant subsidiaries, including NPC and SPPC, fails to pay any indebtedness in excess of $10 million or has any indebtedness of $10 million or more accelerated and declared due and payable.

SPR Floating Rate Notes Exchange

In January 2003, SPR acquired $8.75 million aggregate principal amount of its Floating Rate Notes due April 20, 2003, in exchange for 1,295,211 million shares of its common stock, in two privately negotiated transactions exempt from the registration requirements of the Securities Act of 1933.

SPR Corporate Premium Income Equity Securities (PIES)

PIES Outstanding

On November 16 and 21, 2001, SPR issued an aggregate of $345 million senior unsecured notes in connection with the public offering of 6,900,000 of its Corporate Premium Income Equity Securities (PIES). Each Corporate PIES unit consists of a forward stock purchase contract and a senior unsecured note issued by SPR with a face amount of $50.

Each holder of Corporate PIES is entitled to receive quarterly payments consisting of purchase contract adjustment payments and interest on the senior unsecured notes. The Corporate PIES have a combined rate of 9.0%, which is comprised of the coupon on the senior note of 7.93% and the stated rate of the purchase contract adjustment payments of 1.07%. Interest on the senior unsecured notes began to accrue on November 16, 2001, and quarterly interest payments will be made each quarter beginning with the first payment, which was made on February 15, 2002. All senior unsecured notes will be remarketed beginning on August 10, 2005, up to and including November 1, 2005, and, if necessary, on November 9, 2005, unless holders of senior notes that are not part of a Corporate PIES elect not to have their senior notes remarketed. Upon remarketing, the interest rate will be reset and the senior notes will accrue interest at the reset rate after the remarketing settlement date.

Purchase contract adjustment payments will accrue from November 16, 2001. Holders received the first quarterly purchase contract adjustment payments of $0.1323 per unit ($913,000 in aggregate) on February 15, 2002, and will receive payments of $0.1338 per unit for each subsequent quarter. Originally the aggregate amount of these payments was approximately $923,000. However, subsequent to the partial PIES redemption of February 5, 2003 (discussed below) the quarterly aggregate payments were approximately $643,000.

Upon issuance, a liability for the present value of the purchase contract adjustment payments, approximately $13.7 million, was recorded in Other Deferred Credits, with a corresponding reduction to Other Paid-in-Capital. As of December 31, 2004, the purchase contract adjustment payment liability was approximately $2.5 million.

On February 5, 2003, SPR acquired 2,095,650 of PIES including approximately $104.8 million of 7.93% Senior Notes due 2007 that are a component of the PIES, in exchange for 13,662,393 shares of its common stock in five privately-negotiated transactions exempt from the registration requirements of the Securities Act of 1933. As of December 31, 2004, 4,804,350 PIES and approximately $240 million of senior unsecured notes remain outstanding.

PIES Conversion Features

Each stock purchase contract obligates the holder to purchase SPR common stock on or before November 15, 2005, the Purchase Contract Settlement Date. The number of shares each investor is entitled to receive will depend on the average closing price of SPR common stock over a 20-day trading period prior to the settlement. The total number of common shares SPR will issue upon settlement of the applicable portion of the stock purchase contract on the settlement date will be determined based upon the following criteria.

- A Threshold Appreciation Price was set at $16.62 per share, which was approximately 20% above the last reported sale price of SPR common stock on November 12, 2001, which was $13.85 (the Reference Price).
- If the Applicable Market Value (the 20-trading-day average closing price per share of SPR common prior to the settlement date) is greater than or equal to the Threshold Appreciation Price of $16.62, then the Settlement Rate will be 3.0084 common shares per purchase contract. This is equivalent to shares being issued at a market price of $16.62 (i.e. $50/$16.62=3.0084).
- If the Applicable Market Value is less than the Threshold Appreciation Price of $16.62 but greater than the Reference Price of $13.85, then the Settlement Rate will be equal to $50 divided by the Applicable Market Value (the 20-trading-day average closing price per share of SPR common prior to the settlement date) to arrive at the number of common shares per purchase contract.
- If the Applicable Market Value is less than or equal to the Reference Price of $13.85, then the Settlement Rate will be 3.6101 common shares per purchase contract. This is equivalent to shares being issued at a market price of $13.85 (i.e. $50/$13.85=3.6101).

In no instance will fractional shares will be issued; cash will be paid in lieu of any fractional shares.

PIES Settlement Options

The senior notes are pledged as collateral to secure each holder's obligation to purchase shares of SPR common stock under the stock purchase contract. The senior note may be released from the pledge arrangement if a holder opts to create Treasury PIES by delivering a like principal amount of U.S. Treasury securities to the Securities Intermediary in substitution for the senior notes. Prior to the Purchase Contract Settlement Date, holders of Corporate PIES have the option to pay $50 per Corporate PIES to settle their purchase contract obligations. If the holders do not elect to make a cash payment, the proceeds from the remarketing of the senior notes will be used to satisfy their purchase contract obligations. If any senior notes remain outstanding after the Purchase Contract Settlement Date, SPR will pay interest payments on those senior notes until their maturity on November 15, 2007.

PIES Range of Common Shares to be Issued

At December 31, 2004 there were 4,804,350 SPR PIES outstanding. Depending on the Applicable Market Value on the Settlement Date of November 15, 2005, the range of SPR common shares to be issued would vary between a high of approximately 17,344,000 shares if the common share Applicable Market Value was less than or equal to $13.85, to a low of approximately 14,453,000 shares if the common share Applicable Market Value was greater than or equal to $16.62.

The December 31, 2004 SPR common stock closing price was $10.50 per share. The Applicable Market Value (the 20-trading-day average closing price per share) inclusive of December 31 was $10.22 per SPR common share. Using that average price of $10.22 the criteria of an Applicable Market Value less than or equal to the Reference Price of $13.85 would have been determinate. Thus, utilizing the criteria above, the Settlement Rate would be 3.6101 common shares per purchase contract.

Given the current balance of 4,804,350 PIES outstanding, approximately 17,344,184 (4,804,350 times 3.6101 minus any fractional shares) SPR common shares would be issued at the Settlement Date of November 15, 2005.

For a discussion of the potential effect of this conversion on earnings per share see Note 17, Earnings Per Share.

Sierra Pacific Communications

Sierra Pacific Communications (SPC) was formed as a Nevada corporation in 1999 to identify and develop business opportunities in telecommunications services and infrastructure. SPC entered 2004 with two distinct business areas. The first involved a fiber optic system extending between Salt Lake City, Utah and Sacramento, California (the Long Haul System or System) and the second was the Metro Area Network (MAN) business in Las Vegas and Reno, Nevada.

SPC formed a limited liability company with Touch America, Inc. (TAI) named Sierra Touch America LLC (STA) in 2000, to further the development of the Long Haul System. The project sustained significant cost overruns and several complaints and mechanic's liens were filed against several parties, including STA and SPC, by System contractors and subcontractors. In September 2002, SPC and TAI entered into an agreement whereby SPC redeemed its membership interest in STA and acquired fiber optic assets in the System and an indemnity for System liabilities, for a total purchase price of $48.5 million. SPC also executed a $35 million promissory note in favor of STA. TAI remained as the sole member of STA. In June 2003, TAI and all its subsidiaries (including STA) filed a petition for Chapter 11 bankruptcy protection. SPC pursued litigation in TAI's bankruptcy case to resolve its obligations to, and claims against, TAI and its affiliates. After more than a year of litigation and extensive negotiations among various parties, SPC entered into a settlement agreement dated July 28, 2004, with TAI, STA, and AT&T. The bankruptcy court approved TAI's plan of liquidation and the settlement agreement by order dated October 6, 2004.

Under the terms of the settlement agreement, SPC paid $10 million and granted STA three ducts plus SPC's portion of fiber in the main cable, in satisfaction of SPC's remaining obligations to STA on the $35 million promissory note and an additional $2.3 million toward settlement of the various complaints and mechanic's liens mentioned above. Management does not expect the final outcome to have a significant financial impact.

Lease Commitments

In 1984, NPC entered into a 30-year capital lease with five-year renewal options beginning in year 2015. The fixed rental obligation for the first 30 years is $5.1 million per year. Also, NPC has a power purchase contract with Nevada Sun-Peak Limited Partnership. The contract contains a buyout provision for the facility at the end of the contract term in 2016. The facility is situated on NPC property.

Future cash payments for these capital leases, combined, as of December 31, 2004, were as follows (dollars in thousands):

2005	$ 6,076
2006	6,494
2007	5,932
2008	7,053
2009	7,510
Thereafter	29,957

NOTE 8. FAIR VALUE OF FINANCIAL INSTRUMENTS

The December 31, 2004, carrying amount of cash and cash equivalents, current assets, accounts receivable, accounts payable and current liabilities approximates fair value due to the short-term nature of these instruments.

The total fair value of NPC's consolidated long-term debt at December 31, 2004, is estimated to be $2.4 billion (excluding current portion) based on quoted market prices for the same or similar issues or on the current rates offered to NPC for debt of the same remaining maturities. The total fair value (excluding current portion) was estimated to be $1.9 billion at December 31, 2003.

The total fair value of SPPC's consolidated long-term debt at December 31, 2004, is estimated to be $1.0 billion (excluding current portion) based on quoted market prices for the same or similar issues or on the current rates offered to SPPC for debt of the same remaining maturities. The total fair value (excluding current portion) was estimated to be $936.9 million as of December 31, 2003.

The total fair value of SPR's consolidated long-term debt at December 31, 2004 is estimated to be $4.60 billion (excluding current portion) based on quoted market prices for the same or similar issues or on the current rates offered to SPR for debt of the same remaining maturities. The total fair value (excluding current portion) was estimated to be $3.88 billion as of December 31, 2003.

NOTE 9. DIVIDEND RESTRICTIONS

Since SPR is a holding company, substantially all of its cash flow is provided by dividends paid to SPR by NPC and SPPC on their common stock, all of which is owned by SPR. Since NPC and SPPC are public utilities, they are subject to regulation by state utility commissions, which may impose limits on investment returns or otherwise impact the amount of dividends that the Utilities may declare and pay and to a federal statutory limitation on the payment of dividends. In addition, certain agreements entered into by the Utilities set restrictions on the amount of dividends they may declare and pay and restrict the circumstances under which such dividends may be declared and paid. The specific restrictions on dividends contained in agreements to which NPC and SPPC are party, as well as specific regulatory limitations on dividends, are summarized below.

Dividend Restrictions Applicable to Nevada Power Company

- NPC's Indenture of Mortgage, dated as of October 1, 1953, between NPC and Deutsche Bank Trust Company Americas, as trustee (the First Mortgage Indenture), limits the cumulative amount of dividends and other distributions that NPC may pay on its capital stock. In February 2004, NPC amended this restriction in its First Mortgage Indenture to:
    - change the starting point for the measurement of cumulative net earnings available for the payment of dividends on NPC's capital stock from March 31, 1953 to July 28, 1999 (the date of NPC's merger with SPR), and
    - permit NPC to include in its calculation of proceeds available for dividends and other distributions the capital contributions made to NPC by SPR.

  As amended, NPC's First Mortgage Indenture dividend restriction is not expected to materially limit the amount of dividends that it may pay to SPR in the foreseeable future.

- The following notes, bonds and credit agreement limit the amount of payments that NPC may make to SPR:
    - NPC's 5⅞% General and Refunding Mortgage Notes, Series L, due 2015, which were issued on November 16, 2004,
    - NPC's Revolving Credit Agreement, which was established on October 8, 2004 in connection with the purchase of the Chuck Lenzie Generating Station, and amended and restated on October 22, 2004,
    - NPC's 6½% General and Refunding Mortgage Notes, Series I, due 2012, which were issued on April 7, 2004,
    - NPC's General and Refunding Mortgage Bond, Series H, which was issued December 4, 2003,
    - NPC's 9% General and Refunding Mortgage Notes, Series G, due 2013, which were issued on August 13, 2003, and
    - NPC's 10⅞% General and Refunding Mortgage Notes, Series E, due 2009, which were issued on October 29, 2002.

However, the dividend payment limitation does not apply to payments by NPC to enable SPR to pay its reasonable fees and expenses (including, but not limited to, interest on SPR's indebtedness and payment obligations on account of SPR's Premium Income Equity Securities (PIES)) provided that:

- those payments do not exceed $60 million for any one calendar year,
- those payments comply with any regulatory restrictions then applicable to NPC, and
- the ratio of consolidated cash flow to fixed charges for NPC's most recently ended four full fiscal quarters immediately preceding the date of payment is at least 1.75 to 1.

The terms of the various series of notes, the bond and the revolving credit agreement also permit NPC to make payments to SPR in excess of the amounts payable discussed above in an aggregate amount not to exceed:

- under the Series E Notes, $15 million from the date of the issuance of the Series E Notes, and
- under the Series G, Series I and Series L Notes, the Series H Bond, and the NPC Revolving Credit Agreement $25 million from the date of the issuance of the Series G, Series I and Series L Notes, and the Series H Bond and the establishment of the Revolving Credit Agreement, respectively.

In addition, NPC may make payments to SPR in excess of the amounts described above so long as, at the time of payment and after giving effect to the payment:

- there are no defaults or events of default with respect to the Series E, G, I and L Notes or the Series H Bond or the Revolving NPC Credit Agreement,
- NPC has a ratio of consolidated cash flow to fixed charges for NPC's most recently ended four full fiscal quarters immediately preceding the payment date of at least 2.0 to 1, and
- the total amount of such dividends is less than:
    - the sum of 50% of NPC's consolidated net income measured on a quarterly basis cumulative of all quarters from the date of issuance of the applicable series of Notes, the Bond or Credit Agreement, plus
    - 100% of NPC's aggregate net cash proceeds from contributions to its common equity capital or the issuance or sale of certain equity or convertible debt securities of NPC, plus
    - the lesser of cash return of capital or the initial amount of certain restricted investments, plus
    - the fair market value of NPC's investment in certain subsidiaries.

NOTES TO FINANCIAL STATEMENTS (continued)

If NPC's Series E Notes, Series G Notes, Series I Notes, Series L Notes or Series H Bond are upgraded to investment grade by both Moody's Investors Service, Inc. (Moody's) and Standard & Poor's Rating Group, Inc. (S&P), these restrictions will be suspended and will no longer be in effect so long as the applicable series of Notes or the Bond remains investment grade.

- The terms of NPC's preferred trust securities provide that no dividends may be paid on NPC's common stock if NPC has elected to defer payments on the junior subordinated debentures issued in conjunction with the preferred trust securities. At this time, NPC has not elected to defer payments on the junior subordinated debentures.

Dividend Restrictions Applicable to Sierra Pacific Power Company

- The following notes, bonds and credit facilities limit the amount of payments in respect of common stock that SPPC may make to SPR:
  - SPPC's Revolving Credit Agreement, which was established on October 22, 2004,
  - SPPC's 6¼ % General and Refunding Mortgage Notes, Series H, due 2012, which were issued on April 16, 2004, and
  - SPPC's General and Refunding Mortgage Bond, Series E, which was issued on December 4, 2003.

  However, the dividend payment limitation does not apply to payments by SPPC to enable SPR to pay its reasonable fees and expenses (including, but not limited to, interest on SPR's indebtedness and payment obligations on account of SPR's Premium Income Equity Securities (PIES)) provided that:

  - those payments do not exceed $50 million for any one calendar year,
  - those payments comply with any regulatory restrictions then applicable to SPPC, and
  - the ratio of consolidated cash flow to fixed charges for SPPC's most recently ended four full fiscal quarters immediately preceding the date of payment is at least 1.75 to 1.

  The terms of the Series H Notes, the SPPC Revolving Credit Agreement and the Series E Bond also permit SPPC to make payments to SPR in excess of the amounts payable discussed above in an aggregate amount not to exceed $25 million from the date of the issuance of the Series H Notes, the establishment of the Revolving Credit Agreement and issuance of the Series E Bond, respectively.

In addition, SPPC may make payments to SPR in excess of the amounts described above so long as, at the time of payment and after giving effect to the payment:

- there are no defaults or events of default with respect to the Series H Notes, the SPPC Revolving Credit Agreement or the Series E Bond,
- SPPC has a ratio of consolidated cash flow to fixed charges for SPPC's most recently ended four full fiscal quarters immediately preceding the payment date of at least 2.0 to 1, and
- the total amount of such dividends is less than:
  - the sum of 50% of SPPC's consolidated net income measured on a quarterly basis cumulative of all quarters from the date of issuance of the Series H Notes, the establishment of the revolving credit agreement or the issuance of the Series E Bond, plus
  - 100% of SPPC's aggregate net cash proceeds from contributions to its common equity capital or the issuance or sale of certain equity or convertible debt securities of SPPC, plus
  - the lesser of cash return of capital or the initial amount of certain restricted investments, plus
  - the fair market value of SPPC's investment in certain subsidiaries.

If SPPC's Series H Notes or the Series E Bond are upgraded to investment grade by both Moody's and S&P, these restrictions will be suspended and will no longer be in effect so long as the applicable series of notes or bond remain investment grade.

- SPPC's Articles of Incorporation contain restrictions on the payment of dividends on SPPC's common stock in the event of a default in the payment of dividends on SPPC's preferred stock. SPPC's Articles also prohibit SPPC from declaring or paying any dividends on any shares of common stock (other than dividends payable in shares of common stock), or making any other distribution on any shares of common stock or any expenditures for the purchase, redemption, or other retirement for a consideration of shares of common stock (other than in exchange for or from the proceeds of the sale of common stock) except from the net income of SPPC, and its predecessor, available for dividends on common stock accumulated subsequent to December 31, 1955, less preferred stock dividends, plus the sum of $500,000. At the present time, SPPC believes that these restrictions do not materially limit its ability to pay dividends and/or to purchase or redeem shares of its common stock.

Dividend Restrictions Applicable to Both Utilities

- On March 31, 2004, the PUCN issued an order in connection with its authorization of the issuance of long-term debt securities by NPC. On April 8, 2004, the PUCN issued an order in connection with its authorization of the issuance of long-term debt securities by SPPC. These PUCN orders, for NPC Docket 04-1014 and SPPC Docket 03-12030, permit NPC and SPPC to annually dividend an aggregate of either SPR's actual cash requirements for debt service, or $70 million, whichever is less. These orders, in conjunction with earlier orders on this issue, also provide that the dividend limitation may be reviewed in a subsequent application to grant short-term debt authority and that, in the event that circumstances change in the interim, either NPC or SPPC may petition the PUCN to review the dollar limitation.
- The Utilities are subject to the provision of the Federal Power Act that states that dividends cannot be paid out of funds that are properly included in their capital account. Although the meaning of this provision is unclear, the Utilities believe that the Federal Power Act restriction, as applied to their particular circumstances, would not be construed or applied by the FERC to prohibit the payment of dividends for lawful and legitimate business purposes from current year earnings, or in the absence of current year earnings, from other/additional paid-in capital accounts. If, however, the FERC were to interpret this provision differently, the ability of the Utilities to pay dividends to SPR could be jeopardized.
- On November 6, 2003, the Bankruptcy Court issued an order staying execution pending appeal of the September 26, 2003 judgment entered in favor of Enron against the Utilities. One of the conditions of the stay order is that the Utilities cannot pay dividends to SPR other than for SPR's current operating expenses and debt payment obligations. Although the judgment has been reversed by the U.S. District Court of the Southern District of New York, this limitation will remain in place pursuant to the terms of a stipulation and agreement among the Utilities and Enron.

Assuming that NPC and SPPC meet the requirements to pay dividends under the Federal Power Act and that any dividends paid to SPR are for SPR's debt service obligations and current operating expenses, the most restrictive of the dividend restrictions applicable to the Utilities individually can be found for NPC, in NPC's Series E Notes and, for SPPC, in SPPC's Series H Notes, Series E Bond and its Revolving Credit Agreement. NPC or SPPC, as the case may be, must meet a fixed charge coverage ratio of at least 1.75:1 over the prior four fiscal quarters as a condition to their payment of dividends. Although each Utility currently meets these tests at December 31, 2004, a significant loss by either Utility could cause that Utility to be precluded from paying dividends to SPR until such time as that Utility again meets the coverage test. The dividend restriction in the PUCN order may be more restrictive than the individual dividend restrictions if dividends are paid from both Utilities because the PUCN dividend restriction of either SPR's actual cash requirements for debt service, or $70 million, whichever is less, may be less than the aggregate amount of the Utilities' individual dividend restrictions.

NOTE 10. DERIVATIVES AND HEDGING ACTIVITIES (SPR, NPC, SPPC)

SPR, SPPC, and NPC apply SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138 and SFAS No. 149. As amended, SFAS No. 133 requires that an entity recognize all derivatives as either assets or liabilities in the statement of financial position, measure those instruments at fair value, and recognize changes in the fair value of the derivative instruments in earnings in the period of change unless the derivative qualifies as an effective hedge.

SPR's and the Utilities' current objective in using derivatives is primarily to reduce exposure to energy price risk. Energy price risks result from activities that include the generation and procurement of power and the procurement of natural gas. Derivative instruments used to manage energy price risk include forwards, options, and swaps. These contracts allow the Utilities to reduce the risks associated with volatile electricity and natural gas markets.

The following table shows the amounts recorded on the Consolidated Balance Sheets of SPR, NPC, and SPPC at December 31, 2004 and 2003, due to the fair value of the derivatives. Due to deferred energy accounting under which the Utilities operate, regulatory assets and liabilities are established to the extent that electricity and natural gas derivative gains and losses are recoverable or payable through future rates, once realized (dollars in millions):

	2004			2003		
	SPR	**NPC**	**SPPC**	SPR	NPC	SPPC
Risk management assets	**$14.6**	**$5.1**	**$9.5**	$22.1	$11.7	$10.4
Risk management liabilities	**$ 9.9**	**$3.6**	**$6.3**	$16.5	$ 5.3	$11.2
Risk management regulatory assets	**$ 6.7**	**$3.6**	**$3.1**	$14.3	$ 3.1	$11.2

Also included in risk management assets were $9.2 million, $3.6 million, and $5.6 million in payments for gas options and $2.2 million, $1.5 million, and $.7 million for the Alcan contract for SPR, NPC, and SPPC, respectively, at December 31, 2004.

In connection with SPR's issuance of its Convertible Notes on February 14, 2003 (see Note 7, Long-Term Debt), the conversion option, which is treated as a cash-settled written call option, was separated from the debt and accounted for separately as a derivative instrument in accordance with FASB's EITF Issue 90-19, "Convertible Bonds with Issuer Option to Settle for Cash upon Conversion." Upon issuance, the fair value of the option was recorded as a current liability in Other Current Liabilities and until August 11, 2003, the change in the fair value was recognized in earnings in the period of the change.

On August 11, 2003, SPR obtained shareholder approval to issue up to 42,736,920 additional shares of SPR's common stock in lieu of paying the cash portion of the conversion price. Before SPR received shareholder approval, holders of the Convertible Notes were entitled to receive both shares of common stock and cash upon conversion on their notes. Issue No. 00-19 of the EITF of the FASB, "Accounting for Derivative Instruments Indexed to, and Potentially Settled in, a Company's Own Stock" provides for the recording of the fair value of the derivative in equity, if all of the applicable provisions of EITF Issue No. 00-19 are met. As of August 11, 2003, management believes that all such applicable provisions have been met.

NOTES TO FINANCIAL STATEMENTS (continued)

Accordingly, the fair value of the derivative, $118 million on the date of the shareholder vote, was reclassified to equity at that date. The fair value of this option was determined using the closing stock price, which was $4.68 as of August 11, 2003, the strike price for conversion ($4.5628), a measurement for the volatility of the stock price and the time value of money. The August 11, 2003 valuation resulted in an unrealized gain of $61.5 million in the third quarter of 2003. The valuations at March 31, 2003, and June 30, 2003, resulted in an unrealized gain of $15.9 million in the first quarter and an unrealized loss of $123.5 million in the second quarter. The net impact of changes in market value was an unrealized loss of $46.1 million for the year ended December 31, 2003. EITF Issue No. 00-19 also indicates that subsequent changes in fair value should not be recognized as long as the derivative remains classified in equity. Accordingly, no unrealized gains or losses were recorded after August 11, 2003.

NOTE 11. INCOME TAXES (BENEFITS)

Sierra Pacific Resources

The following reflects the composition of taxes on income from continuing operations (dollars in thousands):

	2004	2003	2002
Provision for Income Taxes:			
Currently (receivable) payable:			
Federal	**$ (161)**	$ 15,481	$ (85,898)
Total currently payable	**(161)**	15,481	(85,898)
Deferred, net:			
Federal	**27,029**	(54,329)	(69,643)
State	**(775)**	—	—
Total deferred, net	**26,254**	(54,329)	(69,643)
Amortization of excess deferred taxes	**(2,196)**	(2,196)	(2,196)
Amortization of investment tax credits	**(3,266)**	(3,163)	(3,454)
Total provision (benefit) for income taxes	**$20,631**	$(44,207)	$(161,191)
Income Statement Classification of Provision (Benefit) for Income Taxes:			
Operating income	**$24,443**	$(57,008)	$(165,249)
Other income	**(3,812)**	12,801	4,058
Total	**$20,631**	$(44,207)	$(161,191)

The total income tax provision differs from amounts computed by applying the federal statutory tax rate to income before income taxes for the following reasons (dollars in thousands):

	2004	2003	2002
Income (loss) from continuing operations	**$35,635**	$(104,160)	$(294,978)
Total income tax expense (benefit)	**20,631**	(44,207)	(161,191)
Pre-tax income (loss)	**56,266**	(148,367)	(456,169)
Statutory tax rate	**35%**	35%	35%
Federal income tax expense (benefit) at statutory rate	**19,693**	(51,928)	(159,659)
Depreciation related to difference in costs basis for tax purposes	**4,834**	4,225	3,081
Allowance for funds used during construction—equity	**(2,082)**	(2,018)	112
ITC amortization	**(3,266)**	(3,163)	(3,454)
Goodwill	**6,332**	—	—
Convertible bond mark to market and interest accretion	**2,786**	18,291	—
Pension benefit plan	**(3,684)**	(1,113)	1,400
Other—net	**(632)**	(5,370)	(2,671)
Provision for income taxes before effect of income tax settlements	**$23,981**	$ (41,076)	$(161,191)
Effective tax rate before effect of income tax settlements	**42.6%**	27.7%	35.3%
Effects of income tax settlements	**(3,350)**	(3,131)	—
Provision for income taxes	**$20,631**	$ (44,207)	$(161,191)
Effective tax rate	**36.7%**	29.8%	35.3%

As a large corporate taxpayer, the SPR consolidated group's tax returns are examined by the Internal Revenue Service on a regular basis. The IRS began an audit of SPR's consolidated income tax returns in the third quarter of 2002. The years under examination include the separate company returns for NPC and its subsidiaries for 1997 and 1998 and the consolidated returns for SPR and its subsidiaries for 1997 through 2001. The focus of the examination is the net operating losses generated in 2000 and 2001 and carried back to earlier years. The losses reported in 2000 and 2001 are mainly due to the deductions claimed for purchased fuel and purchased power. During 2003 and the first quarter of 2004, SPR reached tentative agreements with the IRS for certain matters. As a result of the tentative agreements, SPR recognized tax benefits which increased net income by approximately $3.1 million in 2003 and $3.4 million in 2004. SPR believes that it does not have any contingent income tax liabilities therefore no income tax reserves have been established as of December 31, 2004.

The net deferred income tax liability consists of deferred income tax liabilities less related deferred income tax assets, as shown (dollars in thousands):

	2004	2003
Deferred Income Tax Assets:		
Net operating loss and credit carryovers	**$ 331,434**	$277,129
Employee benefit plans	**(6,406)**	12,415
Reserve for bad debts	**12,669**	15,721
Customer advances	**49,946**	45,839
Gross-ups received on contribution in aid of construction and customer advances	**20,068**	19,264
Excess deferred income taxes	**17,852**	17,469
Unamortized investment tax credit	**22,723**	24,409
Additional minimum pension liability	**720**	16,207
Deferred amortization of land gain	**19,754**	13,759
Provision for contract termination	**123,627**	137,181
Other	**1,442**	6,775
Total Deferred Income Tax Assets before Valuation Allowance	**$ 593,829**	$586,168
Valuation allowance	**(925)**	(575)
Total Deferred Income Tax Assets after Valuation Allowance:	**$ 592,904**	$585,593
Deferred Income Tax Liabilities:		
Bond redemptions	**$ 12,714**	$ 10,712
Deferred conservation programs	**6,226**	2,926
Excess of tax depreciation over book depreciation	**591,874**	499,949
Tax benefits flowed through to customers	**114,854**	155,547
Regulatory asset associated with goodwill	**164,913**	—
Deferred energy	**232,930**	278,229
Ad valorem taxes	**3,340**	3,372
Regulatory assets	**23,286**	23,484
Other	**10,028**	16,309
Total Deferred Income Tax Liabilities	**1,160,165**	990,528
Net Deferred Income Tax Liability	**$ 567,261**	$404,935

SPR's balance sheets contain a net regulatory asset of $239.2 million at December 31, 2004 and $113.7 million at December 31, 2003. The regulatory asset consists of future revenue to be received from customers due to flow-through of the tax benefits of temporary differences and goodwill recognized from the merger of Nevada Power Company and Sierra Pacific Resources. Offset against these amounts are future revenues to be refunded to customers (regulatory liabilities). The regulatory liabilities consist of temporary differences for liberalized depreciation at rates in excess of current rates and unamortized investment tax credits. The regulatory liability for temporary differences related to liberalized depreciation will continue to be amortized using the average rate assumption method required by the Tax Reform Act of 1986. The regulatory liability for temporary differences caused by the investment tax credit will be amortized ratably in the same fashion as the accumulated deferred investment credit.

	2004	2003
As Reflected in SPR's Balance Sheet (dollars in thousands):		
Flow through of tax benefits due to customers	**$114,854**	$155,547
Goodwill	**164,913**	—
Regulatory tax asset	**$279,767**	$155,547
Liberalized depreciation at rates in excess of current rates	**$ 17,852**	$ 17,469
Unamortized investment tax credits	**22,723**	24,409
Regulatory tax liability	**$ 40,575**	$ 41,878
Net regulatory tax asset	**$239,192**	$113,669

In March 2002, NPC received a federal income tax refund of $79.3 million. Additionally, SPR and the Utilities received $105.7 million of refunds in the second quarter of 2002. These refunds were the result of income tax losses generated in 2001. Federal legislation passed in March 2002 changed the allowed period in which these losses could be carried back to prior taxable years from two years to five years. The losses claimed on the tax returns are mainly temporary differences, and as such, are not expected to cause a material impact on SPR's, NPC's, or SPPC's future income statements.

SPR and its subsidiaries file a consolidated federal income tax return. Current income taxes are allocated based on SPR's and each subsidiaries respective taxable income or loss and investment tax credits as if each subsidiary filed a separate return. SPR owes SPPC $63.3 million and NPC $18.6 million in inter-company tax payments.

The following table summarizes the tax NOL and credit carryforwards and associated carryforward periods, and a valuation allowance for amounts which SPR had determined that realization is uncertain (dollars in thousands):

	Deferred Tax Asset	Valuation Allowance	Net Deferred Tax Asset	Expiration Period
Federal NOL	$328,765	$ —	$328,765	2020–2023
State NOLs	1,472	—	1,472	2005–2013
Arizona coal credits	1,197	925	272	2005–2009
Total	$331,434	$925	$330,509	

At December 31, 2004, SPR has gross federal and state net operating loss carryforwards of $939.3 million and $18.1 million, respectively.

Considering all positive and negative evidence regarding the utilization of the SPR's deferred tax assets, it has been determined that SPR is more-likely-than-not to realize all recorded deferred tax assets, except for the Arizona coal credits. As such, these Arizona coal credits represent the only valuation allowance that has been recorded as of December 31, 2004.

NOTES TO FINANCIAL STATEMENTS *(continued)*

Nevada Power Company

The following reflects the composition of taxes on income (dollars in thousands):

	2004	2003	2002
Provision for Income Taxes:			
Currently payable:			
Federal	$ 6	$ 32,612	$ (44,504)
Total currently payable	6	32,612	(44,504)
Deferred, net:			
Federal	58,762	(31,097)	(85,151)
State	(67)	—	—
Total deferred, net	58,695	(31,097)	(85,151)
Amortization of excess deferred taxes	(499)	(499)	(499)
Amortization of investment tax credits	(1,630)	(1,630)	(1,630)
Total provision for income taxes	$56,572	$ (614)	$(131,784)
Income statement classification of provision for income taxes:			
Operating income	$45,135	$(12,734)	$(133,411)
Other income	11,437	12,120	1,627
Total	$56,572	$(614)	$(131,784)

The total income tax provision differs from amounts computed by applying the federal statutory tax rate to income before income taxes for the following reasons (dollars in thousands):

	2004	2003	2002
Income (loss) from continuing operations	$104,312	$19,277	$ (235,070)
Total income tax expense (benefits)	56,572	(614)	(131,784)
Pre-tax income (loss)	160,884	18,663	(366,854)
Statutory tax rate	35%	35%	35%
Federal income tax expense (benefit) at statutory rate	56,309	6,532	(128,399)
Depreciation related to difference in cost basis for tax purposes	2,144	1,431	1,431
Allowance for funds used during construction—equity	(1,481)	(996)	153
ITC amortization	(1,630)	(1,630)	(1,630)
Goodwill	1,732	—	—
Other—net	(502)	(525)	(3,339)
Provision for income taxes before effect of income tax settlements	$ 56,572	$ 4,812	$ (131,784)
Effective tax rate before effects of income tax settlements	35.2%	25.8%	35.9%
Effects of income tax settlements	—	(5,426)	—
Provision for income taxes	$ 56,572	$ (614)	$ (131,784)
Effective tax rate	35.2%	-3.3%	35.9%

The IRS began an audit of SPR's consolidated income tax returns in the third quarter of 2002. The years under examination include the separate company returns for NPC and its subsidiaries for 1997 and 1998 and the consolidated returns for SPR and its subsidiaries for 1997 through 2001. The focus of the examination is the net operating losses generated in 2000 and 2001 and carried back to earlier years. The losses reported in 2000 and 2001 are mainly due to the deductions claimed for purchased fuel and purchased power. During 2003 and the first quarter of 2004, SPR reached tentative agreements with the IRS for certain matters. As a result of the tentative agreements, NPC recognized tax benefits which increased net income by approximately $5.4 million in 2003. NPC believes that it does not have any contingent income tax liabilities therefore no income tax reserves have been established as of December 31, 2004.

The net deferred income tax liability consists of deferred income tax liabilities less related deferred income tax assets, as shown (dollars in thousands):

	2004	2003
Deferred Income Tax Assets:		
Net operating loss and credit carryovers	$221,566	$215,192
Employee benefit plans	(14,436)	5,936
Reserve for bad debts	10,815	14,104
Customer advances	27,735	26,473
Gross-ups received on contributions in aid of construction and customer advances	14,028	13,348
Excess deferred income taxes	6,395	4,860
Unamortized investment tax credit	10,111	10,916
Additional minimum pension liability	307	1,512
Deferred amortization of land gain	19,754	13,759
Provision for contract termination	90,222	99,391
Other—net	1,342	(377)
Total Deferred Income Tax Assets before Valuation Allowance	$387,839	$405,114
Valuation Allowance	(925)	(575)
Total Deferred Income Tax Assets	$386,914	$404,539
Deferred Income Tax Liabilities:		
Bond redemptions	$ 5,538	$ 4,884
Deferred conservation programs	4,171	2,383
Excess of tax depreciation over book depreciation	362,265	283,121
Tax benefits flowed through to customers	63,650	102,282
Goodwill	103,572	—
Deferred energy	175,045	216,494
Ad valorem taxes	3,340	3,372
Regulatory assets	13,162	12,612
Other—net	1,454	1,769
Total Deferred Income Tax Liabilities	732,197	626,917
Net Deferred Income Tax Liability	$345,283	$222,378

NPC's balance sheet contains a net regulatory asset of $150.7 million at December 31, 2004 and $86.5 million at December 31, 2003. The regulatory asset consists of future revenue to be received from customers due to flow-through of the tax benefits of temporary differences and goodwill recognized from the merger of Nevada Power Company and Sierra Pacific Resources. Offset against these amounts are future revenues to be refunded to customers (regulatory liabilities). The regulatory liabilities consist of temporary differences for liberalized depreciation at rates in excess of current rates and unamortized investment tax credits. The regulatory liability for temporary differences related to liberalized depreciation will continue to be amortized using the average rate assumption method required by the Tax Reform Act of 1986. The regulatory liability for temporary differences caused by the investment tax credit will be amortized ratably in the same fashion as the accumulated deferred investment credit.

	2004	2003
As Reflected in SPR's Balance Sheet:		
Flow through of tax benefits due to customers	**$ 63,650**	$102,282
Goodwill	**103,572**	—
Regulatory tax asset	**$167,222**	$102,282
Liberalized depreciation at rates in excess of current rates	**$ 6,395**	$ 4,860
Unamortized investment tax credits	**10,111**	10,916
Regulatory tax liability	**$ 16,506**	$ 15,776
Net regulatory tax asset	**$150,716**	$ 86,506

In March 2002, NPC received a federal income tax refund of $79.3 million. Additionally, SPR and the Utilities received $105.7 million of refunds in the second quarter of 2002. These refunds were the result of income tax losses generated in 2001. Federal legislation passed in March 2002 changed the allowed period in which these losses could be carried back to prior taxable years from two years to five years. The losses claimed on the tax returns are mainly temporary differences, and as such, are not expected to cause a material impact on NPC's future income statements.

SPR and its subsidiaries file a consolidated federal income tax return. Current income taxes are allocated based on SPR's and each subsidiaries respective taxable income or loss and investment tax credits as if each subsidiary filed a separate return. SPR owes NPC $18.6 million in inter-company tax payments.

The following table summarizes the tax NOL and credit carryforwards and associated carryforward periods, and a valuation for amounts which NPC has determined that realization is uncertain (dollars in thousands):

	Deferred Tax Asset	Valuation Allowance	Net Deferred Tax Asset	Expiration Period
Federal NOL	$219,863	$ —	$219,863	2020-2023
State NOL	506	—	506	2005-2008
Arizona coal credits	1,197	925	272	2005-2009
Total	$221,566	$925	$220,641	

At December 31, 2004, NPC has gross federal and state net operating loss carryforwards of $628.2 million and $7.2 million, respectively.

Considering all positive and negative evidence regarding the utilization of NPC's deferred tax assets, it has been determined that NPC is more-likely-than-not to realize all recorded deferred tax assets, except for some of the Arizona coal credits. As such, these Arizona coal credits represent the only valuation allowance that has been recorded as of December 31, 2004.

Sierra Pacific Power Company

The following reflects the composition of taxes on income (dollars in thousands):

	2004	2003	2002
Provision for Income Taxes:			
Currently payable:			
Federal	**$ 690**	$ 10,717	$(16,478)
Total currently payable	**690**	10,717	(16,478)
Deferred, net:			
Federal	**3,676**	(19,724)	15,508
State	**(708)**	—	—
Total deferred, net	**2,968**	(19,724)	15,508
Amortization of excess deferred taxes	**(1,697)**	(1,697)	(1,697)
Amortization of investment tax credits	**(1,636)**	(1,533)	(1,824)
Total provision for income taxes	**$ 325**	$(12,237)	$ (4,491)
Income statement classification of provision for income taxes:			
Operating income	**$ 14,978**	$(13,704)	$ (6,922)
Other income	**(14,653)**	1,467	2,431
Total	**$ 325**	$(12,237)	$ (4,491)

NOTES TO FINANCIAL STATEMENTS (continued)

The total income tax provision differs from amounts computed by applying the federal statutory tax rate to income before income taxes for the following reasons (dollars in thousands):

	2004	2003	2002
Income (loss) from continuing operations	**$18,577**	$(23,275)	$(13,968)
Total income tax expense (benefit)	**325**	(12,237)	(4,491)
Pre-tax income (loss)	**18,902**	(35,512)	(18,459)
Statutory tax rate	**35%**	35%	35%
Federal income tax expense (benefit) at statutory rate	**6,616**	(12,429)	(6,461)
Depreciation related to difference in costs basis for tax purposes	**2,691**	2,794	1,650
Allowance for funds used during construction—equity	**(601)**	(1,022)	(40)
ITC amortization	**(1,636)**	(1,533)	(1,824)
Goodwill	**506**	—	—
Pension benefit plan	**(3,684)**	(1,113)	1,400
Other—net	**(217)**	(491)	784
Provision for income taxes before effect of income tax settlements	**$ 3,675**	$(13,794)	$ (4,491)
Effective tax rate before effects of income tax settlements	**19.4%**	38.8%	24.3%
Effects of income tax settlements	**(3,350)**	1,557	—
Provision for income taxes	**$ 325**	$(12,237)	$ (4,491)
Effective tax rate	**1.7%**	34.5%	24.3%

The IRS began an audit of SPR's consolidated income tax returns in the third quarter of 2002. The years under examination include the consolidated returns for SPR and its subsidiaries for 1997 through 2001. The focus of the examination is the net operating losses generated in 2000 and 2001 and carried back to earlier years. The losses reported in 2000 and 2001 are mainly due to the deductions claimed for purchased fuel and purchased power. During 2003 and the first quarter of 2004, SPR reached tentative agreements with the IRS for certain matters. As a result of the tentative agreements, SPPC recognized tax expense, which decreased net income by approximately $1.6 million in 2003 and increased net income by approximately $3.4 million in 2004. SPPC believes that it does not have any contingent income tax liabilities therefore no income tax reserves have been established as of December 31, 2004.

The net deferred income tax liability consists of deferred income tax liabilities less related deferred income tax assets, as shown (dollars in thousands):

	2004	2003
Deferred Income Tax Assets:		
Net operating loss and credit carryforwards	**$ 6,150**	$ —
Employee benefit plans	**7,596**	6,479
Reserve for bad debt	**1,854**	1,617
Customer advances	**22,211**	19,366
Gross-ups received on contributions in aid of construction and customer advances	**6,040**	5,916
Excess deferred income taxes	**11,457**	12,609
Unamortized investment tax credit	**12,612**	13,493
Additional minimum pension liability	**332**	267
Provision for contract termination	**33,093**	37,790
Other	**57**	2,227
Total Deferred Tax Assets	**$101,402**	$ 99,764
Deferred Income Tax Liabilities:		
Bond redemptions	**$ 7,176**	$ 5,828
Deferred conservation programs	**2,055**	543
Excess of tax depreciation over book depreciation	**229,609**	216,828
Tax benefits flowed through to customers	**51,204**	53,265
Regulatory asset associated with goodwill	**61,341**	—
Deferred energy	**57,885**	61,735
Regulatory assets	**10,124**	10,872
Other	**3,289**	7,693
Total Deferred Tax Liabilities	**422,683**	356,764
Net Deferred Income Tax Liability	**$321,281**	$257,000

The net deferred income tax liability of $331,586 recorded on SPPC's balance sheet includes a $10,305 payable to reflect the tax liability of SPPC as calculated on a stand-alone basis.

SPPC's balance sheets contain a net regulatory asset of $88.5 million at December 31, 2004 and $27.2 million at December 31, 2003. The regulatory asset consists of future revenue to be received from customers due to flow-through of the tax benefits of temporary differences and goodwill recognized from the merger of Nevada Power Company and Sierra Pacific Resources. Offset against these amounts are future revenues to be refunded to customers (regulatory liabilities). The regulatory liabilities consist of temporary differences for liberalized depreciation at rates in excess of current rates and unamortized investment tax credits. The regulatory liability for temporary differences related to liberalized depreciation will continue to be amortized using the average rate assumption method required by the Tax Reform Act of 1986. The regulatory liability for temporary differences caused by the investment tax credit will be amortized ratably in the same fashion as the accumulated deferred investment credit.

	2004	2003
As Reflected in SPR's Balance Sheet:		
Flow thru of tax benefits		
due to customers	**$ 51,204**	$53,265
Goodwill	**61,341**	—
Regulatory tax asset	**$112,545**	$53,265
Liberalized depreciation at rates in		
excess of current rates	**$ 11,457**	$12,609
Unamortized investment tax credits	**12,612**	13,493
Regulatory tax liability	**$ 24,069**	$26,102
Net regulatory tax asset	**$ 88,476**	$27,163

SPR and the Utilities received $105.7 million of refunds in the second quarter of 2002. These refunds were the result of income tax losses generated in 2001. Federal legislation passed in March 2002 changed the allowed period in which these losses could be carried back to prior taxable years from two years to five years. The losses claimed on the tax returns are mainly timing differences, and as such, are not expected to cause a material impact on SPPC's future income statements.

SPR and its subsidiaries file a consolidated federal income tax return. Current income taxes are allocated based on SPR's and each subsidiaries respective taxable income or loss and investment tax credits as if each subsidiary filed a separate return. SPR owes SPPC $63.3 million in inter-company tax payments.

The following table summarizes the tax NOL and credit carryforwards and associated carryforward period, and a valuation allowance for amounts which NPC has determined that realization is uncertain (dollars in thousands):

	Deferred Tax Asset	Valuation Allowance	Net Deferred Tax Asset	Expiration Period
Federal NOL	$5,184	$—	$5,184	2020-2023
State NOL	966	—	966	2010-2013
Total	$6,150	$—	$6,150	

At December 31, 2004, SPPC has gross federal and state net operating loss carryforwards of $14.8 million and $10.9 million, respectively.

Considering all positive and negative evidence regarding the utilization of SPPC's deferred tax assets, it has been determined that the company is more-likely-than-not to realize all recorded deferred tax assets and therefore no valuation allowance has been recorded as of December 31, 2004.

NOTE 12. RETIREMENT PLAN AND POSTRETIREMENT BENEFITS

SPR has pension plans covering substantially all employees. Benefits are based on years of service and the employee's highest compensation for a period prior to retirement. SPR also has other postretirement plans which provide medical and life insurance benefits for certain retired employees. The following tables provide a reconciliation of benefit obligations, plan assets and the funded status of the plans. This reconciliation is based on a September 30 measurement date (dollars in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2004	2003	**2004**	2003
CHANGE IN BENEFIT OBLIGATIONS				
Benefit obligation, beginning of year	**$495,280**	$428,976	**$159,270**	$132,169
Service cost	**17,988**	15,206	**3,058**	2,455
Interest cost	**30,273**	29,400	**9,258**	8,883
Participant contributions	**—**	—	**1,063**	817
Actuarial loss (gain)	**(6,226)**	39,401	**(2,589)**	22,079
Benefits paid	**(17,530)**	(17,703)	**(8,047)**	(7,133)
Benefit obligation, end of year	**$519,785**	$495,280	**$162,013**	$159,270

The accumulated benefit obligation for Pension Benefits at the end of 2004 and 2003 was $423 million and $397 million respectively.

The weighted-average actuarial assumptions used to determine end of year benefit obligations were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2004	2003	**2004**	2003
Discount rate	**6.10%**	6.00%	**6.10%**	6.00%
Rate of compensation increase	**4.50%**	4.50%	**N/A**	N/A

For measurement purposes, a 6% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2005. The rate was assumed to remain at 6% for all future years.

In selecting an assumed discount rate for fiscal year 2004 pension cost, SPR considered the yield on high quality bonds as measured by Moody's Investors Service, Inc. (Moody's) Aa composite bond index. However, to select an assumed discount rate for fiscal year-end 2004 disclosures and for fiscal year 2005 pension cost, SPR's projected benefit payments were matched to the yield curve derived from a portfolio of over 500 high quality Aa bonds with yields within the 40th to 90th percentiles of these bond yields.

NOTES TO FINANCIAL STATEMENTS (continued)

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effect:

Effect on the Postretirement Benefit Obligation	**2004**	2003
Effect of a 1-percentage point increase	**$ 20,791**	$ 19,590
Effect of a 1-percentage point decrease	**$(17,091)**	$(16,086)

SPR contributions for the other postretirement benefits reflect benefit payments made by SPR (dollars in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2004	2003	**2004**	2003
CHANGE IN PLAN ASSETS				
Fair value of plan assets, beginning of year	**$335,512**	$238,834	**$52,040**	$48,425
Actual return on plan assets	**41,528**	57,964	**5,202**	9,709
SPR contributions	**76,782**	56,417	**226**	222
Participant contributions	**—**	—	**1,063**	817
Acquistion and divestiture	**—**	—	**—**	—
Benefits paid	**(17,530)**	(17,703)	**(8,047)**	(7,133)
Fair value of plan assets, end of year	**$436,292**	$335,512	**$50,484**	$52,040

The asset allocation for SPR's pension plans at the end of 2004 and 2003, and the target allocation for 2005, by asset category, follows. The fair value of plan assets for these plans is $436.3 million and $335.5 million, at the end of 2004 and 2003, respectively. The expected long-term rate of return on these plan assets was 8.50% in 2004 and 8.50% in 2003.

	Target Allocation	Percentage of Plan Assets at Year End	
Asset Category	2005	**2004**	2003
Equity securities	60%	**60%**	61%
Debt securities	40	**39**	39
Other	—	**1**	—
Total	100%	**100%**	100%

The asset allocation for the other postretirement benefit plans at the end of 2004 and 2003, and target allocation for 2005, by asset category, follows. The fair value of plan assets for these plans is $50.5 million and $52.0 million at the end of 2004 and 2003, respectively. The expected long-term rate of return on these plan assets was 8.50% in 2004 and 8.50% in 2003.

	Target Allocation	Percentage of Plan Assets at Year End	
Asset Category	2005	**2004**	2003
Equity securities	60%	**60%**	61%
Debt securities	40	**39**	39
Other	—	**1**	—
Total	100%	**100%**	100%

SPR's investment strategy is to ensure the safety of the principal of the assets and obtain asset performance to meet the continuing obligations of the plan. SPR strives to maintain a reasonable and prudent amount of risk, and seeks to limit risk through diversification of assets. Also, SPR considers the ability of the plan to pay all benefit and expense obligations when due, and to control the costs of administering and managing the plan. SPR's investment guidelines prohibit investing the plan assets in real estate and SPR's own stock. Currently, the plan assets are invested in international and domestic equity securities, and fixed securities which include bonds.

Funded Status (dollars in thousands)

	Pension Benefits		Other Postretirement Benefits	
	2004	2003	**2004**	2003
Funded status, end of year	**$ (83,493)**	$(159,768)	**$(111,529)**	$(107,230)
Unrecognized net actuarial (gains) losses	**120,614**	146,708	**66,463**	74,676
Unrecognized prior service cost	**13,322**	15,036	**597**	660
Unrecognized net transition obligation	**—**	—	**7,374**	8,342
Contributions made in 4th quarter	**15,323**	40,313	**—**	—
Accrued pension and postretirement benefit obligations	**$ 65,766**	$ 42,289	**$ (37,095)**	$ (23,552)

Amounts for pension and postretirement benefits recognized in the consolidated balance sheets consist of the following (dollars in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2004	2003	**2004**	2003
Prepaid pension asset	**$ 81,838**	$ 57,465	**N/A**	N/A
Accrued benefit liability	**(16,072)**	(15,176)	**$(37,095)**	$(23,552)
Intangible asset	**31**	15,036	**N/A**	N/A
Accumulated other comprehensive income	**3,451**	48,344	**N/A**	N/A
Additional minimum liability	**(3,482)**	(63,380)	**N/A**	N/A
Net amount recognized	**$ 65,766**	$ 42,289	**$(37,095)**	$(23,552)

At the end of 2004 and 2003, the projected benefit obligation, accumulated benefit obligation, and fair value of plan assets for pension plans with a projected benefit obligation in excess of plan assets, and pension plans with an accumulated benefit obligation in excess of plan assets, were as follows (dollars in thousands):

	Projected Benefit Obligation Exceeds the Fair Value of Plan's Assets	
End of Year	**2004**	2003
Projected benefit obligation	**$519,785**	$495,280
Accumulated benefit obligation	**422,964**	396,916
Fair value of plan assets	**436,292**	335,512

	Accumulated Benefit Obligation Exceeds the Fair Value of Plan's Assets	
End of Year	**2004**	2003
Projected benefit obligation	**$ 21,938**	$495,280
Accumulated benefit obligation	**19,877**	396,916
Fair value of plan assets	**—**	335,512

The accumulated postretirement benefit obligation exceeds plan assets for all of the company's other postretirement benefit plans.

Expected Cash Flows (dollars in thousands)

	Pension Benefits	Other Postretirement Benefits
EMPLOYER CONTRIBUTIONS TO FUNDED PLANS		
2005 (expected)	$ —	$ 237
EXPECTED BENEFIT PAYMENTS		
2005	$ 19,904	$ 7,596
2006	20,821	8,002
2007	21,998	8,448
2008	23,375	8,873
2009	24,961	9,334
2010–2014	157,358	54,466

The above benefit payments are obligations of the indicated plan, and reflect payments which do not include employee contributions. The expected benefit payment information that reflects the employee obligation is almost exclusively paid from plan assets. A small portion of the pension benefit obligation is paid from the plan sponsor's assets.

Net periodic pension and other postretirement benefit costs include the following components (dollars in thousands):

	Pension Benefits		
	2004	2003	2002
Service cost	**$ 17,988**	$ 15,206	$ 11,954
Interest cost	**30,273**	29,400	27,733
Expected return on assets	**(30,632)**	(21,135)	(22,768)
Amortization of:			
Prior service costs	**1,714**	1,966	1,676
Transition obligation	**—**	—	—
Actuarial (gains) losses	**8,971**	10,086	2,252
Net periodic benefit cost	**28,314**	35,523	20,847
Additional charges (credits):			
Special termination charges	**—**	—	1,646
Curtailment credits	**—**	—	—
Total net benefit cost	**$ 28,314**	$ 35,523	$ 22,493

NOTES TO FINANCIAL STATEMENTS (continued)

	Other Postretirement Benefits		
	2004	2003	2002
Service cost	**$ 3,058**	$ 2,455	$ 1,287
Interest cost	**9,258**	8,883	5,599
Expected return on assets	**(4,100)**	(3,860)	(5,044)
Amortization of:			
Prior service costs	**63**	63	187
Transition obligation	**969**	969	969
Actuarial (gains) losses	**4,129**	2,866	—
Net periodic benefit cost	**13,377**	11,376	2,998
Additional charges:			
Special termination charges	**—**	—	58
Curtailment loss	**—**	—	—
Total net benefit cost	**$13,377**	$11,376	$ 3,056

Weighted-average assumptions used to determine net periodic cost

	Pension Benefits			Other Postretirement Benefits		
	2004	2003	2002	**2004**	2003	2002
Discount rate	**6.00%**	6.75%	7.50%	**6.00%**	6.75%	7.50%
Expected return on plan assets	**8.50%**	8.50%	8.50%	**8.50%**	8.50%	8.50%
Rate of compensation increase	**4.50%**	4.50%	4.50%	**N/A**	N/A	N/A

For measurement purposes, a 6% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2005. The rate was assumed to remain at 6% in all future years.

The expected rate of return on plan assets was determined by considering a realistic projection of what assets can earn, given existing capital market conditions, historical equity and bond premiums over inflation, the effect of "normative" economic conditions that may differ from existing conditions, and projected rates of return on reinvested assets.

The expected long-term rate of return on plan assets is 8.25% in 2005.

The assumed health care cost trend rate has a significant effect on the amounts reported. A one percentage point change in the assumed health care cost trend rate would have had the following effect:

One-Percentage Point Change	Increase	Decrease
Effect on service and interest components of net periodic cost	$1,846	$(1,486)

There were no significant transactions between the plan and the employer or related parties during 2004, 2003, or 2002.

NOTE 13. STOCK COMPENSATION PLANS

At December 31, 2004, SPR had several stock-based compensation plans, which are described below.

SPR's executive long-term incentive plan for key management employees, which was approved by shareholders in May 2004, provides for the issuance of up to 7,750,000 of SPR's common shares to key employees through December 31, 2013. The plan permits the following types of grants, separately or in combination: nonqualified and qualified stock options, stock appreciation rights, restricted stock, performance units, performance shares, and bonus stock. During 2004, SPR issued nonqualified stock options, performance shares and restricted stock under the long-term incentive plan.

NonQualified Stock Options

Elected officers and key employees specifically designated by a committee of the Board of Directors are eligible to be awarded nonqualified stock options (NQSO's) based on the guidelines in the plan. These grants are at 100% of the then current fair market value, and vest over different periods, as stated in the grant. These options have to be exercised within ten years of award, and no earlier than one year from the date of grant. At the time of grant, rights to dividend equivalents may also be awarded.

In 2004, SPR granted 45,000 shares with dividend equivalents, which were issued at an option price not less than market value at the date of the grant, and will vest to the participants over one year from the grant date. The grant may be exercised for a period not exceeding ten years from the grant date. The options may be exercised using either cash or previously acquired shares valued at the current market price, or a combination of both. The Committee may also allow cashless exercises, subject to applicable securities law restrictions or other means consistent with the purpose of the plan and the applicable law.

A summary of the status of SPR's nonqualified stock option plan as of December 31, 2004, 2003, and 2002, and changes during the year is presented below:

	2004		2003		2002	
Nonqualified Stock Options	**Shares**	**Weighted Average Exercise Price**	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Outstanding at beginning of year	**1,371,869**	**$16.33**	1,399,809	$16.56	1,213,958	$18.28
Granted	**45,000**	**$ 7.29**	55,000	$ 5.69	502,380	$14.05
Exercised	**8,000**	**$ 5.39**	—	—	—	—
Forfeited	**180,919**	**$17.41**	82,940	$13.25	316,529	$19.16
Outstanding at end of year	**1,227,950**	**$15.91**	1,371,869	$16.33	1,399,809	$16.56
Options exercisable at year-end	**1,215,450**	**$15.99**	1,369,786	$16.35	524,301	$19.07
Weighted average grant date fair value of options granted:(1)						
Average of all grants for:						
2004		**$ 4.96**				
2003				$ 3.61		
2002						$ 4.56

(1) *The fair value of each nonqualified option has been estimated on the date of grant using the Black-Scholes option-pricing model with the following assumptions used for grants issued in 2004, 2003, and 2002:*

Year of Option Grant	Average Dividend Yield	Average Expected Volatility	Average Risk-Free Rate of Return	Average Expected Life
2004	0.00%	52.60%	4.79%	10 years
2003	0.00%	46.97%	4.64%	10 years
2002	0.00%	38.23%	5.03%	10 years

The following table summarizes information about nonqualified stock options outstanding at December 31, 2004:

		Options Outstanding		Options Exercisable	
Year of Grant	Weighted Average Exercise Price	Number Outstanding at 12/31/04	Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable at 12/31/04
1995	$13.02	6,093	< 1 year	$13.02	6,093
1996	$16.23	5,046	1 year	$16.23	5,046
1997	$19.97	17,588	2 years	$19.97	17,588
1998	$24.93	34,560	3 years	$24.93	34,560
1999	$25.35	52,560	4-4.6 years	$25.35	52,560
2000	$16.00	471,366	5 years	$16.00	471,366
2001	$15.08	223,887	6-6.9 years	$15.08	223,887
2002	$14.05	316,850	7-7.9 years	$14.05	316,850
2003	$ 5.69	75,000	8-8.5 years	$ 5.69	75,000
2004	$ 7.29	25,000	9.5 years	$ 7.29	12,500
Weighted Average Remaining Contractual Life			5.68 years		

NOTES TO FINANCIAL STATEMENTS (continued)

Each participant was granted dividend equivalents for all 1996 and prior nonqualified option grants, as well as the new grants made on December 19, 2003 and June 29, 2004. Each dividend equivalent entitles the participant to receive a contingent right to be paid an amount equal to dividends declared on shares originally granted from the date of grant through the exercise date. Dividend equivalents will be forfeited if options expire unexercised or are otherwise terminated.

Restricted Stock Shares

In 2004, SPR granted 283,782 shares of restricted stock at an average grant price of $7.41 per share; these shares will vest over three years from the grant date at one-third per year. During 2004, there were 1,233 shares issued under these grants, according to the vesting schedule.

In 2003, SPR granted 448,576 shares of restricted stock at an average grant price of $5.93 per share. Of the shares granted, 438,576 shares will vest over 4 years with one-third becoming available in each of the years ended December 31, 2004, 2005, and 2006. The remaining 10,000 shares will vest over three years at one-third per year. In 2004, according to the vesting schedule for each grant, 124,286 shares were issued under these grants.

In 2002, SPR granted 4,500 restricted stock shares at an average grant price of $6.55 per share. The grants vest over four years at 25% per year. In 2004, according to the vesting schedule for each grant, 375 shares were issued under these grants.

Employee Stock Purchase Plan

Upon the inception of SPR's employee stock purchase plan, SPR was authorized to issue up to an aggregate of 400,162 shares of common stock to all of its employees with minimum service requirements. On June 19, 2000, shareholders approved an additional 700,000 shares for distribution under the plan. According to the terms of the plan, employees can choose twice each year to have up to 15% of their base earnings withheld to purchase SPR's common stock. The purchase price of the stock is the lesser of 90% of the market value on the offering commencement date, or 100% of the market value on the offering exercise date. Employees can withdraw from the plan at any time prior to the exercise date. Under the plan, SPR sold 77,511, 100,660, and 73,321 shares to employees in 2004, 2003, and 2002, respectively. For purposes of determining the pro forma disclosure, compensation cost has been estimated for the employees' purchase rights on the date of grant using the Black-Scholes option-pricing model with the following assumptions used for 2004, 2003, and 2002 with an option life of six months:

Year	Average Dividend Yield	Average Expected Volatility	Average Risk-Free Rate of Return	Weighted Average Fair Value
2004	0.00%	52.60%	1.79%	$2.24
2003	0.00%	52.40%	0.98%	$1.29
2002	0.00%	38.00%	3.12%	$1.45

NOTE 14. COMMITMENTS AND CONTINGENCIES (SPR, NPC, AND SPPC)

Purchased Power

At December 31, 2004, NPC has eight long-term contracts for the purchase of electric energy. Expiration of these contracts ranges from 2008 to 2024. SPPC has one long-term contract with an expiration date of 2009. In accordance with the Public Utility Regulatory Policies Act, the Utilities are obligated, under certain conditions, to purchase the generation produced by small power producers and cogeneration facilities at costs determined by the appropriate state utility commission. Generation facilities that meet the specifications of the regulations are known as qualifying facilities (QF). As of December 31, 2004, NPC had a total of 305 MWs of contractual firm capacity under contract with four QFs. The contracts terminate between 2022 and 2024. As of December 31, 2004, SPPC had a total of 109 MWs of maximum contractual firm capacity under 15 contracts with QFs. SPPC also has contracts with three projects at variable short-term avoided cost rates. SPPC's long-term QF contracts terminate between 2006 and 2039.

Estimated future commitments under non-cancelable agreements (including agreements with QF's as of December 31, 2004 were as follows (dollars in thousands)):

Purchased Power

	NPC	SPPC	Total
2005	$ 221,625	$29,602	$ 251,227
2006	225,890	30,569	256,459
2007	230,459	31,004	261,463
2008	227,033	32,699	259,732
2009	208,359	17,570	225,929
Thereafter	2,790,045	—	2,790,045

Coal and Natural Gas

The Utilities have several long-term contracts for the purchase and transportation of coal and natural gas. These contracts expire in years ranging from 2005 to 2027. Estimated future commitments under non-cancelable agreements were as follows (dollars in thousands):

	Coal and Gas			Transportation		
	NPC	SPPC	Total	NPC	SPPC	Total
2005	$77,215	$91,883	$169,098	$ 29,631	$ 60,141	$ 89,772
2006	20,082	18,895	38,977	32,591	59,119	91,710
2007	10,243	—	10,243	36,866	55,199	92,065
2008	—	—	—	36,941	48,091	85,032
2009	—	—	—	36,866	39,215	76,081
Thereafter	—	—	—	246,569	309,392	555,961

Leases

SPPC has an operating lease for its corporate headquarters building. The primary term of the lease is 25 years, ending 2010. The current annual rental is $5.4 million, which amount remains constant until the end of the primary term. The lease has renewal options for an additional 50 years.

SPR's estimated future minimum cash payments, including SPPC's headquarters building, under non-cancelable operating leases as of December 31, 2004, were as follows (dollars in thousands):

	Operating Leases		
	NPC	SPPC	Total
2005	$2,068	$ 8,641	$10,709
2006	1,107	8,068	9,175
2007	37	6,967	7,004
2008	11	6,787	6,798
2009	11	6,268	6,279
Thereafter	453	43,331	43,785

Environmental

Nevada Power Company

The Grand Canyon Trust and Sierra Club filed a lawsuit in the U.S. District Court, District of Nevada in February 1998 against the owners (including NPC) of the Mohave Generation Station (Mohave), alleging violations of the Clean Air Act regarding emissions of sulfur dioxide and particulates. An additional plaintiff, National Parks and Conservation Association later joined the suit. The plant owners and plaintiffs have had numerous settlement discussions and filed a proposed settlement with the court in October 1999. The consent decree, approved by the court in November 1999, established emission limits for sulfur dioxide and opacity and required installation of air pollution controls for sulfur dioxide, nitrogen oxides, and particulate matter. The new emission limits must be met by January 1, 2006 and April 1, 2006 for the first and second units, respectively. The estimated cost of new pollution controls and other capital investments is $1.2 billion. As a 14% owner in Mohave, NPC's cost could be $168 million. However, due to the coal and water issues discussed below, it is not the intention of Southern California Edison (SCE) and other owners to proceed with the pollution control equipment.

NPC's ownership interest in Mohave comprises approximately 10% of NPC's peak generation capacity. SCE is the operating partner of Mohave. On May 17, 2002, SCE filed with the CPUC an application to address the future disposition of SCE's share of Mohave. Mohave obtains all of its coal supply from a mine in northeast Arizona on lands of the Navajo Nation and the Hopi Tribe (the Tribes). This coal is delivered from the mine to Mohave by means of a coal slurry pipeline, which requires water that is obtained from groundwater wells located on lands of the Tribes in the mine vicinity.

On October 20, 2004, the CPUC issued a proposed decision which, among other things, directed SCE to continue negotiations with the Tribes regarding post-2005 coal and water supply, and directed SCE to conduct a study of potential alternatives to Mohave. Because coal and water supplies necessary for long-term operation of Mohave have yet to be secured, SCE and the other Mohave co-owners have been prevented from commencing the installation of extensive pollution control equipment that must be put in place if Mohave's operations are extended past 2005.

In May 1997, the Nevada Division of Environmental Protection (NDEP) ordered NPC to submit a plan to eliminate the discharge of Reid Gardner Station wastewater to groundwater. The NDEP order also required a hydrological assessment of groundwater impacts in the area. In June 1999, NDEP determined that wastewater ponds had degraded groundwater quality. In August 1999, NDEP issued a discharge permit to Reid Gardner Station and an order that requires all wastewater ponds to be closed or lined with impermeable liners over the next 10 years. This order also required NPC to submit a Site Characterization Plan to NDEP to ascertain impacts. This plan has been reviewed and approved by NDEP. In collaboration with NDEP, NPC has evaluated remediation requirements. In May 2004, NPC submitted a schedule of remediation actions to NDEP which included proposed dates for corrective action plans and/or suggested additional assessment plans for each specified area. Total new pond construction and lining costs are estimated at approximately $33 million, of which, approximately $20 million has been spent through 2004. Estimated total capital expenditures in 2005 and 2006 are approximately $6 million and $3 million, respectively.

At the Reid Gardner Station, NDEP has determined that there is additional groundwater contamination that resulted from diesel oil spills at the facility. NDEP required NPC to submit a corrective action plan. A hydro-geologic evaluation of the current remediation has been completed, and a dual phase extraction remediation system, which was approved by NDEP, commenced operation in October 2003. The remediation system remains in operation and this effort has shown positive response to cleaning up the diesel oil.

In August 2004, NDEP conducted a Facility Air Quality Operating Permit (Title V permit) inspection at the Reid Gardner Station. Monitoring, recordkeeping, and other reporting items including maintenance records, operating logs, recorded oil/coal data, and other information pertaining to the sources identified in the Title V permit were requested by NDEP. NPC has provided information in connection with this and subsequent requests. In September and October 2004, NPC met with NDEP to review the results of NDEP's inspection. NDEP informed NPC that it may not be in compliance with some elements of its Title V permit, and on December 2, 2004 issued Notices of Alleged Violation (NOAVs). NPC is continuing to provide information to NDEP as requested, and is engaged in discussions with NDEP in an effort to resolve the compliance issues identified in the NOAVs. Because no penalty has been specified by NDEP, and discussions are continuing, management cannot at this time reasonably estimate the amount of any potential penalties that may ultimately be assessed in connection with the alleged violations.

NOTES TO FINANCIAL STATEMENTS (continued)

In July 2000, NPC received a request from the EPA for information to determine the compliance of certain generation facilities at NPC's Clark Station with the applicable State Implementation Plan. In November 2000, NPC and the Clark County Health District entered into a Corrective Action Order requiring, among other steps, capital expenditures at the Clark Station totaling approximately $3 million. In March 2001, the EPA issued an additional request for information that could result in remediation beyond that specified in the November 2000 Corrective Action Order. On October 31, 2003, the EPA issued a violation regarding turbine blade upgrades, which occurred in July 1993. A conference between the EPA and NPC occurred in December 2003. NPC presented evidence on the nature and finding of the alleged violations. In March 2004, the EPA issued another request for information regarding the turbine blade upgrades, and NPC provided information responsive to this request in April and May 2004. It is NPC's position that a violation did not occur and management is presently involved in the discovery process to support this position. Monetary penalties and retrofit control cost, if any, cannot be reasonably estimated at this time.

NEICO, a wholly owned subsidiary of NPC, owns property in Wellington, Utah, which was the site of a coal washing and load-out facility. The site has a reclamation estimate supported by a bond of approximately $5 million with the Utah Division of Oil and Gas Mining, which management believes is sufficient to cover reclamation costs. Currently, management is continuing to evaluate various options including reclamation and sale.

Sierra Pacific Power Company

In September 1994, Region VII of the EPA notified SPPC that it was being named as a potentially responsible party (PRP) regarding the past improper handling of Polychlorinated Biphenyls (PCB's) by PCB Treatment, Inc., in two buildings, one located in Kansas City, Kansas and the other in Kansas City, Missouri (the Sites). Prior to 1994, SPPC sent PCB contaminated material to PCB Treatment, Inc. for disposal. Certificates of disposal were issued to SPPC by PCB Treatment, Inc.; however, the contaminated material was not disposed of, but remained on-site. A number of the largest PRP's formed a steering committee, which has completed site investigations and with the EPA has determined that the Sites should be remediated by removing the buildings to the appropriate landfills. The EPA issued an administrative order on consent requiring the steering committee to oversee the performance of the work. The work to dismantle the buildings and dispose of the debris and impacted soil is currently underway, and is expected to be complete in mid-2006. While the final cost to complete the work is not yet definite, SPPC's share of the cost is not expected to be material.

Litigation Contingencies

Nevada Power Company and Sierra Pacific Power Company

Enron Litigation

Brief Overview

Currently the Utilities are involved in a number of court cases and hearings involving Enron Power Marketing, Inc. (Enron). The cases are as follows: U.S Bankruptcy Court for the Southern District Court of New York (Bankruptcy Court), U.S. District Court for the Southern District Court of New York (U.S. District Court); FERC hearings consisting of the FERC Early Termination, FERC Revocation Show Cause Proceeding, and the FERC Gaming and Show Cause Proceeding. See details of the court cases and hearings below.

In 2003, based on the Bankruptcy Court judgment as detailed below, NPC and SPPC recorded contract termination liabilities of $235 million and $103 million, including pre-judgment interest of $27.8 million and $12.4 million, respectively. Additionally, in order to stay execution of the Judgment, NPC and SPPC have posted into escrow $186 million and $92 million of General and Refunding Mortgage Bonds and $49 million and $11 million in cash as of December 31, 2004. On October 10, 2004, in response to our appeal of the Bankruptcy Court judgment, the U.S. District Court for the Southern District of New York rendered a decision vacating an earlier judgment by the Bankruptcy Court against the Utilities in favor of Enron Power Marketing, Inc. (Enron), and remanded the case back to the Bankruptcy Court for fact-finding. Furthermore, the U.S. District Court held that the pre-judgment interest should have been calculated at the present value rate, rather than at the rate of 1% per month used by the Bankruptcy Court.

Based on the District Court's decision, the Utilities reversed the accrued interest included in contract termination liabilities by approximately $40 million for the year ended 2004. Although the Judgment has been reversed, the terms of NPC's and SPPC's June 30, 2004 stipulation and agreement with Enron, discussed below, will remain in place through the pendency of all remands and appeals of the Judgment. If the Utilities are required to pay part or all of the amounts accrued, the Utilities will pursue recovery of the payments through future deferred energy filing. To the extent that the Utilities are not permitted to recover any portion of these costs through a deferred energy filing, the amount not permitted would be charged as a current operating expense.

A trial date has been set for April 18, 2005 before the Bankruptcy Court. A description of the legal proceedings leading up to District Court's order to vacate follows, along with a discussion of all pending matters related to the Enron litigation.

Bankruptcy Court Judgment

On June 5, 2002, Enron filed suit against the Utilities in its bankruptcy case in the U.S. Bankruptcy Court for the Southern District of New York asserting claims for termination payments Enron claimed it was owed under purchased power contracts with the Utilities. Enron sought liquidated damages in the amount of approximately $216 million from NPC and $93 million from SPPC based on assertions by Enron that it had contractual rights under the Western Systems Power Pool Agreement (WSPPA) to terminate deliveries to the Utilities. Enron based its assertion on a claim that the Utilities did not provide adequate assurance of the Utilities' performance under the WSPPA. The Utilities dispute that they owe the monies sought by Enron and have denied liability on numerous grounds, including termination, deceit and fraud in the inducement, fraud, breach of contract, and unfair trade practices.

On September 26, 2003, the Bankruptcy Court entered a summary judgment (the Judgment) in favor of Enron for damages related to the termination of Enron's power supply agreements with the Utilities. The Judgment required NPC and SPPC to pay approximately $235 million and $103 million, respectively, to Enron for liquidated damages and pre-judgment interest for power not delivered by Enron under the power supply contracts terminated by Enron in May 2002 and approximately $17.7 million and $6.7 million, respectively, for power previously delivered to the Utilities. Based on the pre-judgment rate of 12%, NPC and SPPC recognized additional interest expense of $27.8 million and $12.4 million, respectively, in contract termination liabilities in the third quarter of 2003. Also, NPC and SPPC recorded additional contract termination liabilities for liquidated damages of $6.6 million and $2.1 million, respectively, in the third quarter of 2003. The Bankruptcy Court's order provided that until paid, the amounts owed by the Utilities will accrue interest post-judgment at a rate of 1.21% per annum.

In response to the Judgment, the Utilities filed a motion with the Bankruptcy Court seeking a stay pending appeal of the Judgment and proposing to issue General and Refunding Mortgage Bonds as collateral to secure payment of the Judgment. On November 6, 2003, the Bankruptcy Court ruled to stay execution of the Judgment conditioned upon NPC and SPPC posting into escrow $235 million and $103 million, respectively, of General and Refunding Mortgage Bonds plus $282 thousand in cash by NPC for pre-judgment interest. On December 4, 2003, NPC and SPPC complied with the order of the Bankruptcy Court by issuing NPC's $235 million General and Refunding Mortgage Bond, Series H plus SPPC's $103 million General and Refunding Mortgage Bond, Series E into escrow along with the required cash deposit for NPC. Additionally, the Utilities were ordered to place into escrow $35 million, approximately $24 million and $11 million for NPC and SPPC, respectively, within 90 days from the date of the order, which would lower the principal amount of General and Refunding Mortgage Bonds held in escrow by a like amount. The Utilities made the payments as ordered on February 10, 2004. The Bankruptcy Court also ordered that during the duration of the stay, the Utilities (i) cannot transfer any funds or assets other than to unaffiliated third parties for ordinary course of business operating and capital expenses, (ii) cannot pay dividends to SPR other than for SPR's current operating expenses and debt payment obligations, and (iii) shall seek a ruling from the PUCN to determine whether the cash payments into escrow trigger the Utilities' rights to seek recovery of such amounts through the Utilities' deferred energy rate cases.

On November 21, 2003, the Utilities filed a Petition for Declaratory Order with the PUCN, as required by the Bankruptcy Court's stay order seeking a determination as to whether payment of all or part of the Judgment into escrow would be subject to recovery through a deferred energy accounting adjustment. On February 6, 2004, the PUCN issued its final order indicating that posting or depositing money in escrow would not constitute payment of fuel or purchased power costs eligible for recovery in a deferred account.

A hearing was held on April 5, 2004 before the Bankruptcy Court to review the Utilities' ability to provide additional cash collateral. Prior to the introduction of any testimony or evidence, Enron and the Utilities entered into a settlement whereby NPC agreed to post an additional cash sum of $25 million to be held in escrow pending the issuance of the U.S. District Court's opinion. NPC made the agreed-upon payment on April 16, 2004, which lowered the principal amount of NPC's General and Refunding Mortgage Bond, Series H, currently held in escrow, by a like amount. In addition, Enron agreed not to request any additional collateral from NPC or SPPC during the pendency of the Utilities' appeal of the Judgment to the U.S. District Court for the Southern District of New York.

The Utilities entered into a stipulation and agreement with Enron which was signed by the Bankruptcy Court on June 30, 2004 and provides that (1) the Utilities shall withdraw their objections to the confirmation of Enron's bankruptcy plan, (2) the collateral contained in the Utilities' escrow accounts securing their stay of execution of the Judgment shall not be deemed property of Enron's bankruptcy estate or the Utilities' estates in the event of a bankruptcy filing, and (3) the stay of execution of the Judgment, as previously ordered by the Bankruptcy Court, shall remain in place without any additional principal contributions by the Utilities to their existing escrow accounts during the pendency of any and all of their appeals of the Judgment, including to the United States Supreme Court, until a final non-appealable judgment is obtained. There can be no assurances that the U.S. District Court or any higher court to which the Utilities appeal the Judgment will accept the existing collateral arrangement to secure further stays of execution of the Judgment.

On October 1, 2004, the Bankruptcy Court ruled that Enron was entitled to take the $17.7 million and $6.7 million deposited by NPC and SPPC, respectively, for power previously delivered to them, out of escrow for the benefit of Enron's bankruptcy estate. The Utilities have challenged the Bankruptcy Court's order with respect to these payments, and no final ruling has been made by the Bankruptcy Court.

NOTES TO FINANCIAL STATEMENTS (continued)

Appeal of Bankruptcy Court Judgment to U.S. District Court (SDNY)

On October 1, 2003, the Utilities filed a Notice of Appeal from the Judgment with the U.S. District Court for the Southern District of New York. In the Utilities' appeal, the Utilities sought reversal of the Judgment and contended that Enron is not entitled to recover termination charges under the contracts on various grounds including breach of contract, breach of solvency representation, fraud, misrepresentation, and manipulation of the energy markets and that the Bankruptcy Court erred in holding that the filed rate doctrine barred various claims which were purported to challenge the reasonableness of the rate. Enron filed a cross-appeal on the grounds that the amount of post-judgment interest should have been 12% per year instead of 1.21% as ordered by the Bankruptcy Court.

On October 10, 2004, the U.S. District Court rendered a decision in the Utilities' appeal. The U.S. District Court's decision vacated the judgment entered by the Bankruptcy Court against the Utilities in favor of Enron and remanded the case to the Bankruptcy Court for fact-finding on several issues including:

- whether Enron's demand for assurances at the time of termination of its power supply contracts with NPC and SPPC was reasonable;
- whether the assurances offered by NPC and SPPC to Enron were "reasonably satisfactory assurances"; and
- whether Enron would have been able to perform all of its obligations under each of the power supply contracts at the time the contracts were terminated and following termination.

The District Court further held that the demand for assurances by Enron should have been limited to the amount of its actual loss. The District Court rejected Enron's cross-appeal seeking a 12% per year post-judgment interest rate instead of the 1.21% interest rate ordered by the Bankruptcy Court. The District Court decision also provided that Enron could, if proper, renew its motion to enjoin the proceedings currently before the FERC addressing Enron's termination of its power supply contracts with NPC and SPPC. Although the Judgment has been reversed, the terms of NPC's and SPPC's June 30, 2004 stipulation and agreement with Enron, discussed above, will remain in place through the pendency of all remands and appeals of the Judgment.

The Utilities filed a motion seeking clarification of the District Court rulings with respect to the Utilities' affirmative defenses and counterclaims regarding: fraud by Enron, violation of the Racketeer Influence Corrupt Organizations Act (RICO), anti-trust activities carried out by Enron, the constitutional power of a Bankruptcy Court to enter a final judgment in a "non-core matter," and whether the Bankruptcy Court had properly determined the interest rate applicable to pre-judgment interest. On December 23, 2004, the Court affirmed the dismissal of the Utilities' affirmative defenses and counterclaims were barred under the filed rate doctrine. However, the Court ruled in favor of the Utilities on the calculation of pre-judgment interest.

FERC Early Termination Case

On October 6, 2003, the Utilities filed a Complaint with FERC requesting the opportunity to develop a record regarding three issues: (a) whether Enron exercised reasonable discretion in terminating its various purchased power contracts with the Utilities; (b) whether FERC should exercise its authority to find that Enron is not entitled to collect termination payment profits; and (c) whether Enron should be otherwise denied the authority to collect such payments because to do so would be contrary to the public interest.

On July 22, 2004, the FERC issued an order granting the Utilities' request to the FERC for an expedited hearing to review Enron's termination of the energy contracts entered into between the Utilities and Enron under the WSPPA. Hearings were scheduled to begin on October 25, 2004 and an initial decision was expected from the FERC by December 31, 2004. However, on October 27, 2004, Enron filed a motion in the Bankruptcy Court to enjoin the Utilities from participating in the FERC 206 proceeding. The disposition of this motion is described below.

Bankruptcy Court Injunction and Order Setting Trial

After the U.S. District Court issued its October 10, 2004 ruling, Enron renewed its motion with the Bankruptcy Court seeking to enjoin the Utilities from proceeding in the FERC Early Termination Case. On December 3, 2004, the Bankruptcy Court enjoined the Utilities from further prosecution of the scheduled hearing in the FERC proceeding. The Utilities have appealed this decision and are seeking a stay of the adversary proceeding in the Bankruptcy Court, which is set to begin on April 18, 2005. The Utilities are unable to predict the outcome of the trial at this time.

FERC Revocation Show Cause Proceeding

In March 2003, FERC instituted a "Show Cause" proceeding involving whether Enron's market-based rate authority should be revoked in light of Enron's engagement in illicit trading activities. The Utilities intervened. On June 25, 2003, FERC removed Enron's market-based rate authority, but only on a prospective basis. The Utilities filed a request for rehearing, along with certain other parties. On October 16, 2003, FERC changed the nature of the proceeding, thereby prohibiting further active participation by the interveners (including the Utilities). On December 15, 2003, the Utilities filed an appeal in the United States Circuit Court of Appeals for the District of Columbia concerning these two actions. The appeals have been consolidated with a number of other appeals of FERC's decisions, and the matter is pending. The D.C. Circuit has yet to establish a briefing schedule and there is no current time line for argument or a decision in the case.

FERC Gaming and Partnership Show Cause Proceeding

On June 25, 2003, FERC issued orders in two separate cases involving Enron and potential gaming of power markets. The first was referred to as the "Gaming Show Cause Proceeding" and the second as the "Partnership Show Cause Proceeding." The proceedings focused on Enron's illicit trading activity in California with a variety of counterparties. On July 21, 2004, FERC consolidated the two proceedings and expanded the scope of its inquiry. FERC announced that it was revisiting its decision not to revoke Enron's market-based rate authority and that "Enron potentially could be required to disgorge profits for all of its wholesale power sales in the Western Interconnect for the period January 16, 1997 to June 15, 2003." Enron has sought rehearing of this order, challenging the expanded scope of the proceeding. The Utilities have joined a coalition of other Western Parties and on August 4, 2004, sought clarification that remedies other than disgorgement might be available. On March 11, 2005, the FERC issued an order clarifying issues to be covered in the administrative trial scheduled to begin June 13, 2005. In that order, the FERC stated that Enron's profits under the terminated contracts fell within the scope of that proceeding.

FERC 206 Complaints

In December 2001, the Utilities filed ten complaints with the FERC under Section 206 of the Federal Power Act seeking to reduce prices of certain forward wholesale power purchase contracts that the Utilities entered into prior to the price caps imposed by the FERC in June 2001 relating to the western United States energy crisis. The Utilities believe the prices under these purchased power contracts are unjust and unreasonable. The Utilities negotiated a settlement with Duke Energy Trading and Marketing, but were unable to reach agreement in bilateral settlement discussions with other respondents.

The Utilities are contesting the amounts paid for power actually delivered by these suppliers as well as claims made by terminating power suppliers that did not deliver power, including Enron.

On June 26, 2003, the FERC dismissed the Utilities' Section 206 complaints finding that the strict public interest standard applied to the case and that the company had failed to satisfy the burden of proof required by that standard. On July 28, 2003, the Utilities filed a petition for rehearing at the FERC requesting that the FERC either reconsider or rehear the case. On November 10, 2003, the FERC reaffirmed the June 26, 2003, decision. That decision has been appealed to the United States Court of Appeals for the Ninth Circuit. Oral argument was held on December 8, 2004. A decision is expected within three to six months. The Utilities are unable to predict the outcome of this appeal at this time.

Reliant Antitrust Litigation

On April 22, 2002, Reliant Energy Services, Inc. (Reliant) filed a cross-complaint against NPC and SPPC in the wholesale electricity antitrust cases, which cases were consolidated in the Superior Court of the State of California. Plaintiffs (original plaintiffs consist of The People of the State of California, City and County of San Francisco, City of Oakland, and County of Santa Clara) seek damages and restitution from the named defendants for alleged fraud, misrepresentation, and anticompetitive conduct in manipulating the energy markets in California resulting in prices far in excess of what would otherwise have been a fair price to the plaintiff class in a competitive market. Reliant filed cross-complaints against all energy suppliers selling energy in California who were not named as original defendants in the complaint, denying liability but alleging that if there was liability, it should be spread among all energy suppliers. The court granted motions to dismiss, and the case is currently on appeal. Both NPC and SPPC believe they should have no liability regarding this matter, but at this time management is not able to predict either the outcome or timing of a decision.

Sierra Pacific Resources

In 2000, SPC, a wholly owned subsidiary of SPR, and Touch America, Inc. (TAI, formerly Montana Power) formed Sierra Touch America LLC (STA), a limited liability company whose primary purpose was to engage in communications and fiber optics business projects, including construction of a fiber optic line (the System) between Salt Lake City, Utah, and Sacramento, California. In September 2002, SPC and TAI entered into an agreement whereby SPC redeemed its membership interest in STA and acquired fiber optic assets in the System and an indemnity for System liabilities, for a total purchase price of $48.5 million. SPC executed a $35 million promissory note in favor of STA. TAI remained as the sole member of STA. The project sustained significant cost overruns and several complaints and mechanics liens were filed against several parties, including STA and SPC, by System contractors and subcontractors, including Bayport Pipeline Company and MasTec North America, Inc. In June 2003, TAI and all its subsidiaries (including STA) filed a petition for Chapter 11 bankruptcy protection. SPC pursued litigation in TAI's bankruptcy case to resolve its obligations to, and claims against, TAI and its affiliates. After more than a year of litigation and extensive negotiations among various parties, SPC entered into a settlement agreement dated July 28, 2004, with TAI, STA, and AT&T. The Bankruptcy Court approved TAI's plan of liquidation and the settlement agreement by order was entered on October 6, 2004. The settlement stipulates that SPC will pay a total of $10 million to STA, $6 million of which was paid to STA in July 2004, and grant STA three ducts plus SPC's portion of fiber in the main cable in satisfaction of the remaining amount due on the $35 million promissory note. In October 2004, SPC paid $4 million, the remaining balance provided for under the settlement, and $2.3 million in satisfaction of the various complaints and mechanics liens mentioned above. See Note 18, Discontinued Operations and Disposal and Impairment of Long-Lived Assets.

NOTES TO FINANCIAL STATEMENTS (continued)

Nevada Power Company

Morgan Stanley Proceedings

On September 5, 2002, Morgan Stanley Capital Group (MSCG) initiated arbitration pursuant to the arbitration provisions in various power supply contracts terminated by MSCG in April 2002. In the arbitration, MSCG requested that the arbitrator compel NPC to pay MSCG $25 million pending the outcome of any dispute regarding the amount owed under the contracts. NPC claimed that nothing is owed under the contracts on various grounds, including breach by MSCG in terminating the contracts, and further, that the arbitrator does not have jurisdiction over NPC's contract claims and defenses. In March 2003, the arbitrator dismissed MSCG's demand for arbitration and agreed that the issues raised by MSCG were not calculation issues subject to arbitration and that NPC's contract defenses were likewise not arbitrable.

NPC filed a complaint for declaratory relief in the U.S. District Court for the District of Nevada asking the Court to declare that NPC is not liable for any damages as a result of MSCG's termination of its power supply contracts. On April 17, 2003, MSCG answered the complaint and filed a counterclaim against NPC alleging non-payment of the termination payment in the amount of $25 million. In April 2003, MSCG also filed a complaint against NPC at the FERC alleging that NPC should be required to pay MSCG the amount of the claimed termination payment pending resolution of the case. MSCG filed a motion to intervene in the Section 206 action commenced by NPC against Enron at the FERC, and the FERC denied MSCG's motion. On October 23, 2003, NPC filed a motion to stay the District Court proceedings, pending guidance on applicable legal principles from the FERC, which guidance may be provided in connection with a complaint NPC filed against Enron with regard to exercise of default and early termination rights. On February 2, 2004, the District Court granted NPC's motion, and NPC's complaint for declaratory relief before that court is now stayed pending FERC guidance. On July 22, 2004, the FERC issued an order stating that it would convene a hearing regarding the NPC complaint against Enron (discussed above). On August 11, 2004, NPC filed a motion to continue the stay, and on October 4, 2004, the Court granted the stay for another 90 days. At the February 28, 2005 status conference, the Judge lifted the stay and ordered the case to go forward. The parties will meet to set the discovery and trial schedule. On February 28, 2005, NPC filed a motion for summary judgment. At this time, NPC is unable to predict the outcome or timing of the District Court complaint.

El Paso Merchant Energy

In September 2002, El Paso Merchant Energy (EPME) terminated all forward contracts for energy with NPC for alleged defaults under the WSPPA consisting of alleged failure to pay full contract price for power under NPC's "delayed" payment program which extended from May 1 to September 15, 2002. In October 2002, EPME asserted a claim against NPC for $29 million in damages representing $19 million unpaid under contracts for delivered power during the period May 15 to September 15, 2002, together with approximately $10 million in alleged mark to market damages for future undelivered power. With interest, the amount presently claimed by EPME is $42 million. NPC alleges that EPME's termination resulted in net payments due to NPC under the WSPPA for liquidated damages measured by the difference between the contract price and market price of energy EPME was to deliver from 2004 to 2012. The precise amount due would depend on the manner in which the termination payments are calculated.

In June 2003, EPME demanded mediation of its claim for a termination payment arising out of EPME's September 25, 2002, termination of all executory purchase power contracts between NPC and EPME. The mediation was unsuccessful, and on July 25, 2003, NPC commenced an action against EPME and several of its affiliates in the Federal District Court for the District of Nevada for damages resulting from breach of these purchase power contracts. Discovery is ongoing and the case is set for trial to commence in September 2005. At this time, NPC is unable to predict either the outcome or timing of a decision in this matter.

Reliant Resources and IDACORP Energy, L.P.

On May 3, 2002, and July 3, 2002, respectively, Reliant Resources (Reliant) and IDACORP Energy, L.P. (Idaho) terminated their power deliveries to NPC. On May 20, 2002, and July 10, 2002, Reliant and Idaho asserted claims for $25.6 million and $8.9 million, respectively, under the WSPPA for liquidated damages under energy contracts that each company terminated before the delivery dates of the power. Such claims are subject to mandatory mediation and, in some cases, arbitration under the contracts. With respect to Idaho's claim, Idaho requested mediation of the contracts. On June 30, 2004, Idaho and NPC entered into a settlement agreement whereby Idaho's claims have been dismissed with prejudice in return for a $5 million payment by NPC.

Peabody Western Coal Company

NPC owns an 11%, 255 MW interest in the Navajo Generating Station (Navajo) located in Northern Arizona. Besides NPC, the Salt River Project (Salt River), Arizona Public Service Company, Los Angeles Department of Water and Power, and Tucson Electric Power Company (together the Joint Owners), are partners in Navajo, which includes three coal-fired electrical generating units operated by Salt River.

In January 2005, the Joint Owners were served with a complaint from Peabody Western Coal Co. (Peabody), filed in Missouri State Court in St. Louis (Cause No. 042-08561). Peabody asserts claims against the Joint Owners seeking reimbursement of royalties and other costs and breach of the coal supply agreement.

As operating agent for the project, Salt River has engaged counsel and is defending the suit on behalf of the Joint Owners. On February 20, 2005, the Joint Owners filed Notice of Removal of the compliant to the U. S. District Court, Eastern District of Missouri. NPC believes these claims are without merit and intends to contest them.

Sierra Pacific Power Company

Farad Dam

SPPC owns 4 hydro generating plants (10.3 MW capacity) located in California that were to be included in the sale of SPPC's water business for $8 million to the Truckee Meadows Water Authority (TMWA) in June 2001. Sale of the assets is dependent on CPUC approval. Although approval was expected from the CPUC in the spring of 2004, the CPUC is yet to authorize the transfer and the timing of their decision is not known.

The contract with TMWA requires that SPPC transfer the hydro assets in working condition. However, one of the four hydro generating plants, Farad 2.8 MW, has been out of service since the summer of 1996 due to a collapsed flume. While planning the reconstruction, a flood on the Truckee River in January 1997 destroyed the diversion dam. SPPC filed a claim with the insurers for the flume and dam and in December 2003, SPPC sued the insurers in Federal Court on a coverage dispute relating to potential rebuild costs. The current estimate to rebuild the diversion dam, if management decides to proceed, is approximately $20 million. Management believes that it has a valid insurance claim and is likely to recover the costs to rebuild the dam through the courts. Accordingly, management has not recorded a loss contingency for the cost to rebuild the dam.

Other Legal Matters

SPR and its subsidiaries, through the course of their normal business operations, are currently involved in a number of other legal actions, none of which has had or, in the opinion of management, is expected to have a significant impact on their financial positions, results of operations, or cash flows.

Contract Termination Liabilities

At December 31, 2004, included in NPC's and SPPC's Consolidated Balance Sheets as "Contract termination liabilities," were approximately $246 million and $94 million of charges, respectively, for terminated power supply contracts and associated interest. Correspondingly, pursuant to the deferred energy accounting provisions of AB 369, included in NPC and SPPC deferred energy balances as of December 31, 2004, were approximately $240 million and $84 million of charges, respectively, for recovery in rates in future periods associated with the terminated power supply contracts. If NPC and SPPC are required to pay part or all of the amounts accrued, the Utilities will pursue recovery of the payments through future deferred energy filings. To the extent that the Utilities are not permitted to recover any portion of these costs through a deferred energy filing, the amounts not permitted would be charged as a current operating expense. A significant disallowance of these costs by the PUCN could have a material effect on the future financial position, results of operations, and cash flows of SPR, NPC, and SPPC.

NOTE 15. COMMON STOCK AND OTHER PAID-IN CAPITAL

Rights Agreement

On September 21, 1999, the Board of Directors of SPR (the Board) declared a dividend distribution of one right (Right) for each outstanding share of SPR common stock to shareholders of record at the close of business on October 31, 1999. By issuing the new Rights, the Board extended the benefits and protections afforded to shareholders under the Rights Agreement, dated as of October 31, 1989, which expired on October 31, 1999. Each Right, initially evidenced by and traded with the shares of SPR common stock, entitles the registered holder (other than an "Acquiring Person" as defined in the Rights Agreement) to purchase at an exercise price of $75.00, $150.00 worth of common stock at its then-market value, subject to certain conditions and approvals set forth in the Rights Agreement.

If at any time while there is an Acquiring Person, SPR engages in a merger or other business combination transaction or series of related transactions in which the common stock is changed or exchanged or 50% or more of its assets or earning power is transferred, each Right (not previously voided by the occurrence of a Flip-in Event, as described in the Rights Agreement) will entitle its holder to purchase, at the Right's then-current exercise price, common stock of such Acquiring Person having a calculated value of twice the Right's then-current exercise price.

The Rights are not exercisable until the Distribution Date (as defined in the Rights Agreement) and expire on October 31, 2009, unless previously redeemed by SPR. Following a Distribution Date, the Rights will trade separately from the common stock and will be evidenced by separate certificates. Until the Right is exercised, the holder thereof will have no rights as a shareholder of SPR, including, without limitation, the right to receive dividends. The purpose of the plan is to help ensure that SPR's shareholders receive fair and equal treatment in the event of any proposed hostile takeover of SPR.

Employee Stock Ownership Plans

As of December 31, 2004, 8,747,587 shares of common stock were reserved for issuance under the Common Stock Investment Plan (CSIP), Employees' Stock Purchase Plan (ESPP), and Executive Long-Term Incentive Plan (LTIP).

The 2004 LTIP for officers and key employees allows for the issuance of SPR's common shares through December 31, 2013, which can be earned and issued prior to December 31, 2013. This Plan permits the following types of grants, separately or in combination: nonqualified and qualified stock options; stock appreciation rights; restricted stock; performance units; performance shares, bonus stock and cash.

NOTES TO FINANCIAL STATEMENTS (continued)

SPR also provides an ESPP to all of its employees meeting minimum service requirements. Employees can choose twice each year (offering date) to have up to 15% of their base earnings withheld to purchase SPR common stock. The purchase price of the stock is 90% of the market value on the offering date or 100% of the market price on the execution date, if less.

The Non-employee Director Stock Plan provides that a portion of SPR's outside directors' annual retainer be paid in SPR common stock. SPR records the costs of these plans in accordance with Accounting Principles Board Opinion No. 25. In addition, in 1996 SPR eliminated its outside director retirement plan and converted the present value of each director's vested retirement benefit to phantom stock based on the stock price at the time of conversion. Phantom stock earns dividends, also payable in phantom stock, which are recorded in each Director's phantom account. The value of these accounts is issued in stock or cash, at the election of the Board, at the time the Director leaves the Board.

Non-Employee Director Stock

The annual retainer for non-employee directors is $30,000, and the minimum amount to be paid in SPR stock is $20,000 per director. During 2004, 2003, and 2002, SPR granted the following total shares and related compensation to directors in SPR stock, respectively: 18,740, 39,370, and 18,540 shares, and $140,000, $150,000, and $160,000.

Convertible Notes Issuance

On February 14, 2003, SPR issued and sold $300 million of its 7.25% Convertible Notes due 2010. On August 11, 2003, SPR obtained shareholder approval to issue additional shares of SPR's common stock in lieu of paying the cash payment component upon conversion of the Convertible Notes. If the noteholders were to present the Convertible Notes for conversion and SPR were to fully convert the notes into stock, the number of additional shares required would be 65,749,110. For additional information regarding these Convertible Notes see Note 7, Long-Term Debt.

The Convertible Notes provide for the payment of dividends to the holders in an amount equal to any per share dividends on SPR common stock that would have been payable to the holders if the holders of the notes had converted their notes into shares of common stock at the applicable conversion rate on the record date for such dividend. See Note 17, Earnings Per Share, for a discussion on the effect on the convertible notes and the calculation of basic and diluted EPS.

Stock Exchange Transactions

In January 2003, SPR acquired $8.75 million aggregate principal amount of its Floating Rate Notes due April 20, 2003 in exchange for 1,295,211 shares of its common stock, in two privately negotiated transactions exempt from the registration requirements of the Securities Act of 1933.

NOTE 16. PREFERRED STOCK

Sierra Pacific Power Company

Preferred Stock

SPPC's Restated Articles of Incorporation, as amended on August 19, 1992, authorize an aggregate amount of 11,780,500 shares of preferred stock at any given time. SPPC's preferred stock is superior to SPPC's common stock with respect to dividend payments (which are cumulative) and liquidation rights. SPPC paid $3.9 million in dividends for the year ending December 31, 2004.

On February 8, 2005, a dividend of $975,000 (.04875 per share) was declared on SPPC's preferred stock. The dividend was paid on March 1, 2005 to holders of record as of February 7, 2005.

The following table indicates the dollar amount and number of shares of SPPC preferred stock outstanding at December 31 of each year (dollars in thousands).

	Amount		Shares Outstanding	
Preferred Stock	**2004**	2003	**2004**	2003
Not subject to mandatory redemption				
SPPC Class A Series I	**$50,000**	$50,000	**2,000,000**	2,000,000
Total Preferred Stock	**$50,000**	$50,000	**2,000,000**	2,000,000

NOTE 17. EARNINGS PER SHARE

The difference, if any, between Basic EPS and Diluted EPS is due to potentially dilutive common shares resulting from stock options, the employee stock purchase plan, performance and restricted stock plans, the non-employee director stock plan and dividend participation rights associated with the convertible debt. However, due to net losses for the years ended December 31, 2003 and 2002 these items are anti-dilutive. Accordingly, Diluted EPS for these periods are computed using the weighted average shares outstanding before dilution. Potentially dilutive common shares were determined using the method discussed below.

SPR currently has outstanding $300 million in convertible subordinated 7.25% notes due 2010, or Convertible Notes, that are entitled to receive (non-cumulative) dividend payments on a 1:1 basis in dividends with common shareholders without exercising the conversion option. These Convertible Notes meet the criteria of a participating security in the calculation of basic EPS, and are convertible at the option of the holders into 65,749,110 common shares.

The EITF of the FASB nullified the guidelines given in EITF Topic D-95 with regards to the effect of participating convertible securities on the computation of basic EPS, by issuing EITF 03-6. Under Topic D-95, companies were required to include the effect of participating securities that are convertible to common stock in basic EPS, using either the "if-converted" or the "two-class" method, if the effect is dilutive. EITF 03-6 now requires using the "two-class" method to record the effect of participating securities in the computation of basic EPS, and the "if-converted" method in the computation of diluted EPS, if the effect is dilutive. SPR adopted EITF 03-6 for financial statements issued after March 31, 2004. The "two-class" method was used to calculate basic EPS for the period ending December 31, 2004. This method was not used to calculate basic EPS for the period ending December 31, 2003, as the effect was anti-dilutive. The Convertible Notes were issued after 2002.

The following table outlines the calculation for earnings per share (EPS) (dollars in thousands except per share amounts):

	2004	2003	2002
BASIC EPS			
NUMERATOR ($000)			
Income (loss) continuing operations	$ **35,635**	$ (104,160)	$ (294,979)
Income (loss) from discontinued operations and disposal of subsidiary	$ **(3,164)**	$ (32,469)	$ (7,076)
Cumulative effect of change in accounting principle	$ **—**	$ —	$ (1,566)
Earnings (deficit) applicable to common stock	$ **18,310**	$ (140,529)	$ (307,521)
Earnings (deficit) applicable to convertible notes	$ **10,261**	$ —	$ —
Earnings (deficit) used for basic calculation	$ **28,571**	$ (140,529)	$ (307,521)
DENOMINATOR			
Weighted average number of common shares outstanding	**117,331,365**	115,774,810	102,126,079
Shares from conversion of notes	**65,749,110**	—	—
Shared used for basic EPS	**183,080,475**	115,774,810	102,126,079
PER-SHARE AMOUNT			
Income (loss) continuing operations	$ **0.19**	$ (0.90)	$ (2.89)
Income (loss) from discontinued operations and disposal of subsidiary	$ **(0.02)**	$ (0.28)	$ (0.07)
Cumulative effect of change in accounting principle	$ **—**	$ —	$ (0.02)
Earnings (deficit) applicable to common stock	$ **0.16**	$ (1.21)	$ (3.01)
Earning (deficit) applicable to convertible notes	$ **0.16**	$ —	$ —
DILUTED EPS(1)			
NUMERATOR ($000)			
Income (loss) from continuing operations	$ **35,635**	$ (104,160)	$ (294,979)
Income (loss) from discontinued operations and disposal of subsidiary	$ **(3,164)**	$ (32,469)	$ (7,076)
Cumulative effect of change in accounting principle	$ **—**	$ —	$ (1,566)
Earnings (deficit) applicable to common stock	$ **28,571**	$ (140,529)	$ (307,521)
DENOMINATOR(3),(4)			
Weighted average number of shares outstanding before dilution(2)	**183,080,475**	115,774,810	102,126,079
Stock options	**24,949**	—	—
Executive long-term incentive plan—restricted shares	**264,823**	—	—
Executive long-term incentive plan—performance shares	**—**	—	—
Non-Employee Director stock plan	**15,028**	—	—
Employee stock purchase plan	**15,028**	—	—
	183,400,303	115,774,810	102,126,079
PER-SHARE AMOUNT			
Income (loss) continuing operations	$ **0.19**	$ (0.90)	$ (2.89)
Income (loss) from discontinued operations and disposal of subsidiary	$ **(0.02)**	$ (0.28)	$ (0.07)
Cumulative effect of change in accounting principle	$ **—**	$ —	$ (0.02)
Earnings (deficit) applicable to common stock	$ **0.16**	$ (1.21)	$ (3.01)

(1) The "if-converted" method of calculating diluted EPS was not used for periods ending December 31, 2004 and 2003 due to its anti-dilutive effect.

(2) Weighted average number of shares outstanding for the period ended December 31, 2004 was adjusted by adding 65,749,110 shares for the Convertible Notes.

(3) The denominator does not include stock equivalents for stock options, executive long-term incentive plan—restricted shares and performance shares, non-employee Director stock plan and employee stock purchase plan, for periods ending December 31, 2003 and 2002, due to their anti-dilutive effect. The amounts for periods ending December 31, 2003 and 2002 that would be included in the calculation would be 87,321 and 32,096 shares, respectively.

(4) The denominator also does not include stock equivalents resulting from the conversion of the Corporate PIES and Nonqualified stock option plan for periods ending December 31, 2004, 2003, and 2002, due to conversion prices being higher than market prices for all periods. The amounts that would be included in the calculation, if the conversion price were met, would be 17.3 million, 17.3 million, and 24.9 million shares for Corporate PIES and 1.1 million, 1.4 million, and 1.5 million shares for the Nonqualified stock option plan for periods ending December 31, 2004, 2003, and 2002 respectively.

NOTES TO FINANCIAL STATEMENTS (continued)

NOTE 18. DISCONTINUED OPERATIONS AND DISPOSAL AND IMPAIRMENT OF LONG-LIVED ASSETS

Effective January 1, 2002, SPR, NPC, and SPPC adopted SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," which addresses financial accounting and reporting for the impairment or disposal of long-lived assets. SFAS No. 144 requires a component of an entity that either has been disposed of or is classified as held for sale to be reported as discontinued operations if certain conditions are met. Further, SFAS No. 144 requires that assets to be held and used be tested for recoverability whenever events or circumstances indicate that its carrying amount may not be recoverable.

e·three Business Sale

SPR's subsidiary, e·three, was organized in October 1996 to provide energy and other business solutions in commercial and industrial markets.

In keeping with management's strategy to focus on its core utility businesses, SPR sold e.three on September 26, 2003. The operation of e·three was included in the "Other" business segment.

The operation of e·three discussed above is classified as a discontinued operation in the accompanying consolidated statements of operations.

Other Property Disposals

On January 15, 2003, NPC sold a parcel of land located on Flamingo Road near the Barbary Coast Casino in Las Vegas, Nevada. NPC received cash proceeds of approximately $18 million for the property and retained an easement and other rights necessary to maintain aerial power lines that cross the property. Also, it was agreed that NPC will receive an additional $2.6 million from the sale if the power lines that cross the property are removed and the other rights are relinquished within a five-year period from the date of the sale. The property had been originally transferred to NPC at no cost. The transaction resulted in a gain of $17.7 million, which will be recognized into revenue over a period of three years consistent with the accounting treatment directed by the PUCN.

On July 17, 2003, NPC sold a parcel of land located on Centennial Road in North Las Vegas, Nevada. NPC received cash proceeds of approximately $4.9 million for the property. The property had a carrying value of approximately $1.2 million. The transaction resulted in an approximate gain of $3.7 million, which will be recognized into revenue over a period of two years consistent with the accounting treatment directed by the PUCN.

On August 12, 2003, NPC auctioned parcels of land located on Flamingo Road from Koval Lane to Maryland Parkway, commonly known as "the Flamingo Corridor." The net sales price for these properties was $24.4 million. The carrying value of the properties was approximately $0.2 million. The sale closed on October 28, 2003. The transaction resulted in an approximate gain of $24.2 million, of which $2.4 million is being held in escrow pending the final outcome of related litigation. The gain will be recognized in revenue over a period of four years consistent with the accounting treatment directed by the PUCN.

Sierra Pacific Communications

SPC was formed as a Nevada corporation in 1999 to identify and develop business opportunities in telecommunications services and infrastructure. SPC's business activities have included the development of a fiber optic system extending between Salt Lake City, Utah and Sacramento, California (Long Haul Assets) and the development of Metro Area Networks (MAN) in Las Vegas and Reno, Nevada.

In keeping with management's strategy to focus on its core utility business, SPR sold SPC's MAN assets on June 30, 2004. SPC recognized a gain on the sale of assets of approximately $2.5 million (pre-tax) in connection with the sale of the MAN assets.

Management also concluded to dispose of SPC's Long Haul Assets as part of a settlement with Touch America and Sierra Touch America (STA) in their bankruptcy proceeding. SPC entered into a settlement agreement dated July 28, 2004, with TAI, STA, and AT&T. The bankruptcy court approved TAI's plan of liquidation and the settlement agreement by order dated October 6, 2004.

Under the terms of the settlement agreement, SPC paid $10 million and granted STA three ducts plus SPC's portion of fiber in the main cable, in satisfaction of SPC's remaining obligations to STA on the $35 million promissory note and an additional $2.3 million toward settlement of the various complaints and mechanic's liens mentioned above.

The assets and liabilities associated with the discontinued operation of SPC are segregated on the consolidated balance sheets at December 31, 2004 and 2003. Revenues from SPC for the year ended December 31, 2004 and 2003 were $957,000 and $1.6 million, respectively, and pre-tax loss of approximately $4.9 million and $38 million. The carrying amount of major asset and liability classifications are as follows (dollars in thousands):

	December 31,	
	2004	2003
Investments and other property, net	**$20,000**	$36,512
Cash	**2**	32
Current assets—other	**105**	3,528
	$20,107	$40,072
Current maturities of long-term debt	**$ —**	$19,666
Current liabilities	**10,200**	10,995
Deferred credits—other	**—**	5,205
	$10,200	$35,866

In light of the bankruptcy of Touch America Holdings and STA, SPC evaluated its business to determine whether the Touch America bankruptcy has caused an impairment of SPC's assets. SPC anticipates that the market for fiber optic cable and conduits will likely become significantly over-supplied and has recognized an impairment charge of $32.9 million during the second quarter of 2003. The asset impairment charge consisted of $14.7 million of fiber optic cable, conduits, and other related business equipment write-downs related to SPC's MAN, and $18.2 million in fiber optic cable, conduits, and other related business equipment write-downs of its long haul network assets.

This evaluation was conducted in conformance with the guidelines of SFAS No. 144, and also considered factors such as the anticipated liquidation of Sierra Touch America LLC assets, resulting in significant changes in business climate and projected discounted cash flows from the assets. SPC evaluated its MAN assets using projected discounted cash flows. The evaluation factored the undiscounted cash flows from current and projected sales contracts and continued operating expenses over the approximate 18-year remaining life of the assets and then discounted those cash flows to the end of the current reporting period. SPC evaluated its long haul network assets based in part on a pending sale for a portion of the long haul network assets currently under construction and in part by prices for similar assets adjusted for the market factors that resulted from the Touch America bankruptcy discussed above.

NOTE 19. GOODWILL AND OTHER MERGER COSTS

On March 26, 2004, the PUCN issued a decision on NPC's general rate case that included the recovery of goodwill and other merger costs allocated to NPC resulting from the merger of SPR and NPC in 1999. In its decision, the PUCN affirmed that NPC demonstrated merger savings exceeded merger costs, the requisite requirement for recovery of goodwill and merger costs through rates charged to NPC customers in accordance with the PUCN order approving the merger. The PUCN decision permits NPC to recover approximately $4 million per year during the next two years beginning April 1, 2004, which is based on a forty-year amortization of NPC's total goodwill. The amount to be recovered over the next two years reflects a reduction of 20% from the amounts sought by NPC, or approximately $1 million per year, due to customer satisfaction survey results that the PUCN determined required improvement. The decision requires NPC to again demonstrate in its next general rate application that merger savings continue during the test period in that case. The PUCN's order in that case will determine if any further documentation of merger savings is required in the future. Management expects that it will be able to demonstrate continued savings as a result of the merger as well as satisfactory customer survey results. As a result of the PUCN decision, goodwill of approximately $198 million was reclassified as a regulatory asset and then transferred from the financial statements of SPR to the financial statements of NPC as of March 31, 2004.

On May 27, 2004, the PUCN approved a settlement agreement, previously entered into by SPPC, the Staff of the PUCN and other interveners in connection with SPPC's 2003 general rate case that permits SPPC recovery of goodwill and other merger costs assigned to SPPC's electric business. SPPC is permitted to recover approximately $2.4 million per year during the next two years beginning June 1, 2004, based on a forty-year amortization of goodwill costs. Similar to the decision reached in NPC's rate case described above, in order to continue to recover goodwill costs SPPC is required to again demonstrate in its next general rate application that merger savings continue during the test period in that case. Management expects that it will be able to demonstrate continued savings resulting from the merger. As a result of the PUCN decision, goodwill of approximately $96 million was reclassified to a regulatory asset and transferred from the financial statements of SPR to the financial statements of SPPC as of June 30, 2004. See Note 3, Regulatory Actions for more information regarding the NPC and SPPC general rate decisions.

NOTES TO FINANCIAL STATEMENTS (continued)

In addition to amounts discussed above, SPR's Consolidated Balance Sheet as of March 31, 2004, included approximately $4 million of goodwill assigned to SPR's unregulated operations and $31 million of goodwill allocated to its regulated operations that was not considered for recovery in NPC's or SPPC's general rate cases described above. The $31 million of goodwill was comprised of approximately $19 million assigned to SPPC's regulated gas business and $2 million and $10 million for non-Nevada jurisdictional sales allocated to NPC's and SPPC's electric businesses, respectively. SPPC expects to demonstrate in its next general rate case for the gas distribution business that savings from the merger allocable to the gas business exceed goodwill and other merger costs and, as a result, to recover goodwill and merger costs through future gas rates. Accordingly, management has not reviewed goodwill assigned to the gas business for impairment. However, the approximate $12 million of goodwill assigned to NPC's and SPPC's electric businesses that is not recoverable through future rates and approximately $4 million of goodwill assigned to SPR's unregulated operations were subject to impairment review under the provisions of SFAS No. 142.

SFAS No. 142 provides that an impairment loss is to be recognized if the carrying value of each reporting unit's goodwill exceeds its fair value. For purposes of testing goodwill for impairment, a discounted cash flow model was developed for NPC's and SPPC's electric business and for SPR's unregulated businesses to determine the fair value of each reporting unit as of March 31, 2004. As part of the impairment testing analysis, management revised certain underlying assumptions utilized in previously performed preliminary analyses, that included, revised cash flow forecasts, an increase in the discount rate applied to future cash flows and other assumptions related to the outcomes of NPC's and SPPC's general rate cases. As a result of this impairment testing, SPR recorded a goodwill impairment charge related to NPC's and SPPC's electric reporting units of approximately $2 million and $10 million as a charge to other operating expenses in SPR's, NPC's and SPPC's Consolidated Statements of Operations for the quarter ended March 31, 2004. Goodwill assigned to SPR's unregulated businesses was determined not to be impaired.

The change in the carrying amount of goodwill for the year ended December 31, 2004 and the allocation of the remaining balance is as follows (dollars in thousands):

	Regulated Operations	Unregulated Operations	Total
Goodwill balance as of January 1, 2004	$ 305,982	$3,989	$ 309,971
Goodwill included in regulatory assets as of January 1, 2004	19,070	—	19,070
Subtotal	325,052	3,989	329,041
Transfer to NPC regulatory asset as of March 31, 2004	(197,998)	—	(197,998)
Impairment loss recognized as of March 31, 2004	(11,696)	—	(11,696)
Transfer to SPPC regulatory asset as of June 30, 2004	(96,470)	—	(96,470)
Balance as of December 31, 2004	$ 18,888	$3,989	$ 22,877
Goodwill Allocation to Reporting Units:			
SPPC GAS	$ 18,888	$ —	$ 18,888
SPR's unregulated businesses	—	3,989	3,989
Balance as of December 31, 2004	$ 18,888	$3,989	$ 22,877

NOTE 20. QUARTERLY FINANCIAL DATA (UNAUDITED)

The following figures are unaudited and include all adjustments necessary in the opinion of management for a fair presentation of the results of interim periods. Dollars are presented in thousands except per share amounts.

Sierra Pacific Resources

Quarter Ended	March 31, 2004(1)	June 30, 2004	September 30, 2004	December 31, 2004
Operating revenues	$588,117	$677,420	$903,915	$654,387
Operating income	$ 46,086	$ 74,734	$162,268	$ 55,697
Income (loss) from continuing operations	$(42,800)	$ (40,942)(6)	$ 91,749	$ 27,628(7)
Income (loss) from discontinued operations	$ (675)	$ (2,967)	$ (127)	$ 605
Earnings (deficit) applicable to common stock	$(44,450)	$ (44,884)	$ 90,647	$ 27,258
Income (loss) per share—basic:				
From continuing operations	$ (0.37)	$ (0.35)	$ 0.50	$ 0.15
From discontinued operations	$ (0.01)	$ (0.03)	$ (0.00)	$ —
Earnings (deficit) applicable to common stock	$ (0.38)	$ (0.38)	$ 0.50	$ 0.15
Income (loss) per share—diluted:				
From continuing operations	$ (0.37)	$ (0.35)	$ 0.50	$ 0.15
From discontinued operations	$ (0.01)	$ (0.03)	$ (0.00)	$ —
Earnings (deficit) applicable to common stock	$ (0.38)	$ (0.38)	$ 0.50	$ 0.15

Quarter Ended	March 31, 2003(1)	June 30, 2003	September 30, 2003	December 31, 2003
Operating revenues	$602,512	$ 666,251	$904,347	$614,433
Operating income	$ 46,824	$ 6,193	$165,147	$ 53,300(5)
Income (loss) from continuing operations	$ (8,307)(2)	$(188,311)(3)	$109,978(4)	$ (17,520)
Loss from discontinued operations	$ (1,937)	$ (27,965)	$ (1,231)	$ (1,336)
Earnings (deficit) applicable to common stock	$ (11,219)	$(217,251)	$107,772	$ (19,831)
Income (loss) per share—basic:				
From continuing operations	$ (0.07)	$ (1.61)	$ 0.60	$ (0.15)
From discontinued operations	$ (0.02)	$ (0.24)	$ (0.01)	$ (0.01)
Earnings (deficit) applicable to common stock	$ (0.10)	$ (1.85)	$ 0.59	$ (0.17)
Income (loss) per share—diluted:				
From continuing operations	$ (0.07)	$ (1.61)	$ 0.29(8)	$ (0.15)
From discontinued operations	$ (0.02)	$ (0.24)	$ (0.01)	$ (0.01)
Earnings (deficit) applicable to common stock	$ (0.10)	$ (1.85)	$ 0.28	$ (0.17)

NOTES TO FINANCIAL STATEMENTS (continued)

	Originally Reported March 31, 2004	Adjustment for Discontinued Operations	Revised March 31, 2004
Operating revenues	$588,480	$ (363)	$588,117
Operating income	$ 45,560	$ 526	$ 46,086
Income (loss) from continuing operations	$ (43,475)	$ 675	$ (42,800)
Loss from discontinued operations	$ —	$ (675)	$ (675)
Loss applicable to common shareholders	$ (44,450)	$ —	$ (44,450)
Income (loss) per share—basic:			
From continuing operations	$ (0.37)	$ 0.01	$ (0.37)
From discontinued operations	$ —	$(0.01)	$ (0.01)
Earnings (deficit) applicable to common stock	$ (0.38)	$ —	$ (0.38)
Income (loss) per share—diluted:			
From continuing operations	$ (0.37)	$ 0.01	$ (0.37)
From discontinued operations	$ —	$(0.01)	$ (0.01)
Earnings (deficit) applicable to common stock	$ (0.38)	$ —	$ (0.38)

(1) The amounts previously reported in the March 2004 10Q differ from the amounts currently reported due to 1st quarter amounts being revised to reflect the discontinued operations presentation. Amounts were revised as shown below.

(2) During the first quarter of 2003 SPR recorded an unrealized gain of $16 million on the derivative instrument associated with the $300 million of convertible debt discussed in Note 10, Derivatives and Hedging Activities in the 2004 Annual Report on form 10K.

(3) Income from continuing operations was negatively affected by an unrealized loss of $124 million on the derivative instrument associated with the $300 million of convertible debt in Note 10, Derivatives and Hedging Activities in the 2004 Annual Report on form 10K and loss due to the recognition of asset impairment of $33 million.

(4) Income from continuing operations was affected by an unrealized gain of $61.5 million on the derivative instrument associated with the $300 million of convertible debt as discussed in Note 10, Derivatives and Hedging Activities in the 2004 Annual Report on form 10K and higher interest cost that included recognition of $40.2 million in interest as a result of the Bankruptcy Court judgment regarding Enron. See Note 14 of Notes to Financial Statements, Commitments and Contingencies in the 2004 Annual Report on form 10K.

(5) In the fourth quarter of 2003, SPR recognized charges of approximately $6.3 million (pre-tax) and $4.0 million (net of tax) from the correction of errors related to prior years (2000-2002) which were determined to be immaterial to the respective prior periods.

(6) In the second quarter 2004, income from continuing operations includes the write-off of $47.1 million in disallowed plant costs at SPPC.

(7) In the fourth quarter of 2004, income from continuing operations includes the reversal of $40 million in interest expense due to the decision on the appeal of the Enron bankruptcy judgment.

(8) The "if-converted" method was used to calculate diluted EPS for the quarter ended September 30, 2003.

Nevada Power Company

Quarter Ended	**March 31, 2004**	**June 30, 2004**	**September 30, 2004**	**December 31, 2004**
Operating revenues	**$326,533**	**$449,925**	**$633,609**	**$374,025**
Operating income	**$ 21,000**	**$ 49,470**	**$120,842**	**$ 25,178**
NET INCOME (LOSS)	**$ (15,406)**	**$ 13,590**	**$ 86,198**	**$ 19,930** (3)

Quarter Ended	March 31, 2003	June 30, 2003	September 30, 2003	December 31, 2003
Operating revenues	$331,652	$425,512	$639,661	$359,321
Operating income	$ 17,413	$ 10,484(1)	$127,737	$ 28,099
NET INCOME (LOSS)	$ (15,246)	$ (22,192)	$ 62,524(2)	$ (5,809)

(1) Reflects the write-off of $46 million in May 2003 of disallowed deferred energy costs.

(2) Reflects the charges of $27.8 million of interest cost as a result of the Bankruptcy Court judgment regarding Enron as discussed in Note 14, Commitments and Contingencies in the 2004 Annual Report on form 10K.

(3) In the fourth quarter of 2004, net income includes the reversal of $28 million in interest expense due to the decision on the appeal of the Enron bankruptcy judgment.

Sierra Pacific Power Company

Quarter Ended	**March 31, 2004**	**June 30, 2004**	**September 30, 2004**	**December 31, 2004**
Operating revenues	**$261,317**	**$224,304**	**$270,002**	**$280,037**
Operating income	**$ 27,642**	**$ 17,892**	**$ 39,055**	**$ 26,656**
NET INCOME (LOSS)	**$ 7,671**	**$ (32,187)** (3)	**$ 21,788**	**$ 21,305** (4)
Earnings (deficit) applicable to common stock	**$ 6,696**	**$ (33,162)**	**$ 20,813**	**$ 20,330**

Quarter Ended	March 31, 2003	June 30, 2003	September 30, 2003	December 31, 2003
Operating revenues	$270,071	$240,899	$264,407	$254,489
Operating income (loss)	$ 23,820	$ (8,050)(1)	$ 32,588	$ 20,208
NET INCOME (LOSS)	$ 3,998	$ (27,955)	$ (317)(2)	$ 999
Earnings (deficit) applicable to common stock	$ 3,023	$ (28,930)	$ (1,292)	$ 24

(1) Reflects the write-off of $45 million in June 2003 of disallowed deferred energy costs.

(2) Reflects the charges of $12.4 million of interest cost as a result of the Bankruptcy Court judgment regarding Enron as discussed in Note 14, Commitments and Contingencies in the 2004 Annual Report on form 10K.

(3) In the second quarter 2004, net income includes the write-off of $47.1 million in disallowed plant costs at SPPC.

(4) In the fourth quarter of 2004, net income includes the reversal of $12 million in interest expense due to the decision on the appeal of the Enron bankruptcy judgment.

SHAREHOLDER INFORMATION

CORPORATE DOCUMENTS

The SEC Annual Report on Form 10-K is available free of charge by written request to the company's corporate headquarters. Address request to:

Shareholder Relations
Sierra Pacific Resources
P.O. Box 30150
Reno, Nevada 89520-3150

INDEPENDENT ACCOUNTANT

Deloitte & Touche LLP
Reno, Nevada

ANALYST CONTACT

Britta Carlson
Sierra Pacific Resources
Investor Relations
P.O. Box 98910
Las Vegas, Nevada 89151-0001
(702) 367-5624

NYSE SYMBOL

Sierra Pacific Resources' common stock is traded on the New York Stock Exchange under the symbol SRP.

SHAREHOLDER RELATIONS OFFICE

For shareholder records and dividend disbursement information, contact our Shareholder Relations Department:

Shareholder Relations
Sierra Pacific Resources
6100 Neil Rd.
Reno, Nevada 89511
(800) 662-7575 or (775) 834-3610
Fax: (775) 834-3614

Mailing Address:

P.O. Box 30150
Reno, Nevada 89520-3150

E-mail Address: sharerelations@sppc.com
Web Site: www.sierrapacificresources.com

COMMON STOCK INVESTMENT PLAN

Sierra Pacific Resources' Common Stock Investment Plan offers a simple and convenient method of investing common stock dividends and/or making optional cash investments to purchase additional shares of common stock directly from the company.

Please direct questions or requests for a prospectus to our Shareholder Relations Department.

STOCK TRANSFER AGENT AND REGISTRAR

Wells Fargo Shareowner Services
161 North Concord Exchange St.
South St. Paul, Minnesota 55075-1139

Our transfer agent is responsible for changes in certificate shares only. All other shareholder services are the responsibility of the Shareholder Relations Department in Reno, Nevada.

LOST OR STOLEN CERTIFICATES

If your stock certificates have been lost, stolen, or destroyed, please notify our Shareholder Relations Department in writing immediately.

ACCOUNT CONSOLIDATION

You may consolidate your accounts by contacting the Shareholder Relations Department. If your account registrations are different, it may be necessary to reissue stock certificates.

ANNUAL SHAREHOLDERS' MEETING

The annual shareholders' meeting is scheduled to be held in the convention center at The Texas Station Gambling Hall and Hotel, 2101 Texas Star Lane, North Las Vegas, Nevada, at 10 a.m. on Monday, May 2, 2005.

2004 ANNUAL REPORT

The Annual Report to Shareholders and the statements and statistics contained herein have been assembled for informative purposes and are not intended to induce, or for use in connection with, any sale or purchase of securities. Under no circumstances is this report or any part of its contents to be considered a prospectus, or as an offer to sell, or the solicitation of an offer to buy, any securities.

STOCK INFORMATION

SPR's Common Stock is traded on the New York Stock Exchange (symbol SRP). The dividends paid per share and high and low sale prices of the Common Stock in the consolidated transaction reporting system in "The Dow Jones News Retrieval Service" for 2004 and 2003 are as follows:

	Dividends Paid Per Share	High	Low
2004			
First Quarter	**$.000**	**$8.530**	**$7.190**
Second Quarter	**.000**	**7.900**	**6.570**
Third Quarter	**.000**	**9.000**	**7.550**
Fourth Quarter	**.000**	**10.54**	**8.930**
2003			
First Quarter	$.200	$7.350	$2.850
Second Quarter	.000	5.950	3.220
Third Quarter	.000	6.230	4.560
Fourth Quarter	.000	7.530	4.920

SIERRA PACIFIC RESOURCES—BOARD OF DIRECTORS


Walter M. Higgins


Joseph B. Anderson, Jr.


Mary Lee Coleman


Krestine M. Corbin


Theodore J. Day


James R. Donnelley


Jerry E. Herbst


John F. O'Reilly


Philip G. Satre


Clyde T. Turner

Joseph B. Anderson, Jr.
Chairman and CEO of TAG Holdings, LLC, a holding company for manufacturing and service-related enterprises.

Mary Lee Coleman
President of Coleman Enterprises, a developer of shopping centers and industrial parks.

Krestine M. Corbin
President and Chief Executive Officer of Sierra Machinery, a manufacturer of skiving and roller burnishing machines for industrial use.

Theodore J. Day
Chairman of Dacole Company, an investment firm; formerly Senior Partner of Hale, Day, Gallagher Company, a real estate brokerage and investment firm.

James R. Donnelley
Partner in Stet and Query, Ltd., a family-owned investment company.

Jerry E. Herbst
Chief Executive Officer of Terrible Herbst, Inc., a gas station, car wash, convenience store chain and Herbst Supply Co., Inc., a wholesale fuel distributor.

Walter M. Higgins
Chairman, President and Chief Executive Officer of Sierra Pacific Resources; Chairman and Chief Executive Officer of Nevada Power Company and Sierra Pacific Power Company.

John F. O'Reilly
Chairman and Chief Executive Officer of O'Reilly and Ferrario, LLC, a law firm; Chairman and/or Board member or officer of various family-owned business entities.

Philip G. Satre
Retired Chairman of the Board of Harrah's Entertainment, Inc., a casino-resort company.

Clyde T. Turner
Chairman and CEO of Turner Investments, Ltd., a general-purpose investment company; Principal of several special-purpose real estate development companies.

SIERRA PACIFIC RESOURCES—SENIOR OFFICERS

Walter M. Higgins
Chairman, President and Chief Executive Officer

Michael W. Yackira
Corporate Executive Vice President and Chief Financial Officer

Donald L. "Pat" Shalmy
Corporate Senior Vice President, Policy & External Affairs; President, Nevada Power Company

Jeffrey L. Ceccarelli
Corporate Senior Vice President, Service Delivery & Operations; President, Sierra Pacific Power Company

Ernest E. East
Corporate Senior Vice President, General Counsel and Secretary

Roberto R. Denis
Corporate Senior Vice President, Generation & Energy Supply

Stephen R. Wood
Corporate Senior Vice President, Administration

100% post-consumer

SIERRA PACIFIC RESOURCES
P.O. Box 30150
Reno, NV 89520-3150
www.sierrapacificresources.com