Sierra Pacific™
RESOURCES

2003 ANNUAL REPORT

SIERRA PACIFIC RESOURCES IN BRIEF

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

The company's chief operating subsidiaries are Nevada Power Company and Sierra Pacific Power Company, which serve approximately one million electric customers. Their combined 54,500 square mile service area covers most of Nevada, including Las Vegas and Reno, plus the Lake Tahoe area of northern California. Sierra Pacific Power also provides natural gas service to approximately 129,000 customers in the Reno-Sparks metropolitan area.

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 common stock was 21,856 as of December 31, 2003.

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 Sierra Pacific Resources (SPR), Nevada Power Company (NPC), and Sierra Pacific Power Company (SPPC).

The July 28, 1999 merger between SPR and NPC was treated for accounting purposes as a reverse acquisition and deemed to have occurred on August 1, 1999. As a result, for financial reporting and accounting purposes, NPC was considered the acquiring entity under Accounting Principles Board Opinion No. 16, "Business Combinations," even though SPR became the legal parent of NPC. Because of this accounting treatment, for the year ended December 31, 1999, the table below reflects twelve months of information for NPC and five months of information for SPR and its pre-merger subsidiaries.

Year ended December 31,	2003(3)	2002(2)	2001(1)	2000	1999
(dollars in thousands, except per share amounts)					
Operating Revenues	$2,789,158	$2,985,304	$4,575,261	$2,325,111	$1,279,065
Operating Income (Loss)	$ 248,249	$ (32,049)	$ 221,723	$ 125,685	$ 162,333
Income (Loss) from Continuing Operations	$ (129,375)	$ (300,851)	$ 32,898	$ (46,253)	$ 50,029
Earnings (Loss) from Continuing Operations Per Average Common Share—Basic	$ (1.12)	$ (2.95)	$ 0.38	$ (0.59)	$ 0.80
Earnings (Loss) from Continuing Operations Per Average Common Share—Diluted	$ (1.12)	$ (2.95)	$ 0.38	$ (0.59)	$ 0.80
Total Assets	$7,063,758	$7,110,639	$8,132,727	$5,804,251	$5,348,659
Long-Term Debt	$3,579,674	$3,257,596	$3,570,750	$2,378,312	$1,801,260
Dividends Declared Per Common Share	$ —	$ 0.20	$ 0.40	$ 1.00	$ 1.17

(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 the year ended 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 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 the year ended December 31, 2002 was severely affected by the write-off of deferred energy costs and related carrying charges of $523 million as a result of the Public Utilities Commission of Nevada (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. See Major Factors Affecting Results of Operations, included in Management's Discussion and Analysis of Financial Condition and Results of Operations for further discussion.

(3) Loss from Continuing Operations for the year ended 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, $46 million and $45 million write-off of deferred energy costs by NPC and SPPC, respectively, the impairment of Sierra Pacific Communications of $32.9 million, and approximately $52 million of interest charges related to the Enron Litigation.

SELECTED FINANCIAL DATA—NEVADA POWER COMPANY

Year ended December 31,	**2003**	2002(2)	2001(1)	2000	1999
(dollars in thousands)					
Operating Revenues	**$1,756,146**	$1,901,034	$3,025,103	$1,326,192	$ 977,262
Operating Income (Loss)	**$ 183,733**	$ (104,003)	$ 144,364	$ 74,182	$ 116,983
Net Income (Loss)	**$ 19,277**	$ (235,070)	$ 63,405	$ (7,928)	$ 38,787
Total Assets	**$4,210,759**	$4,166,988	$4,791,261	$2,980,326	$2,790,709
Long-Term Debt	**$1,899,709**	$1,683,310	$1,802,680	$1,122,497	$1,125,717
Dividends Declared—Common Stock	**$ —**	$ 10,000	$ 33,000	$ 64,267	$ 72,000

(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 the year ended 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 compared to other years due to volumes of wholesale electric power to other utilities and hedging activity.*

(2) *Net Loss and Total Assets for the year ended December 31, 2002 was severely affected by the write-off of $465 million of deferred purchased fuel and power costs and related carrying charges. See Major Factors Affecting Results of Operations, included in Management's Discussion and Analysis of Financial Condition and Results of Operations for further discussion.*

SELECTED FINANCIAL DATA—SIERRA PACIFIC POWER COMPANY

Year ended December 31,	**2003(3)**	2002(2)	2001(1)	2000	1999
(dollars in thousands)					
Operating Revenues	**$1,029,866**	$1,081,034	$1,547,430	$ 995,722	$ 709,374
Operating Income	**$ 68,566**	$ 55,292	$ 78,968	$ 45,409	$ 112,703
Income (Loss) from Continuing Operations	**$ (23,275)**	$ (13,968)	$ 22,743	$ (4,077)	$ 64,615
Total Assets	**$2,362,469**	$2,457,516	$2,760,770	$2,258,389	$2,131,069
Long-Term Debt	**$ 912,800**	$ 914,788	$ 923,070	$ 655,816	$ 675,430
Dividends Declared—Common Stock	**$ 18,530**	$ 44,900	$ 63,000	$ 85,000	$ 76,000

(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 the year ended 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 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 ended December 31, 2002 was severely affected by the write-off of $58 million of deferred purchased fuel and power costs and related carrying charges. See Major Factors Affecting Results of Operations, included in Management's Discussion and Analysis of Financial Condition and Results of Operations for further discussion.*

(3) *Loss from Continuing Operations for the year ended December 31, 2003 was affected by the write-off of $45 million in June 2003 of disallowed deferred energy costs and interest charges of $12.4 million related to the Enron litigation. See Major Factors Affecting Results of Operations, included in Management's Discussion and Analysis of Financial Condition and Results of Operations for further discussion.*

TO OUR SHAREHOLDERS:

Walter M. Higgins
Chairman, President and Chief Executive Officer

For several years now, as a result of the Western Energy Crisis and the financial repercussions that followed, your company has confronted the twin challenges of strengthening our financial condition and continuing to provide reliable service to our customers. Serving the fastest-growing market in the United States makes this an especially daunting task for Sierra Pacific Resources. I am pleased to report, however, that both of our utilities continued to meet the reliability demands on their operations during 2003 while at the same time making significant progress in bettering our financial picture.

While much difficult work lies ahead to restore investor value, we have established some fundamental business strategies that will lead us to achieving our goals. They are:

- Retaining and improving access to financial and energy supply markets;
- Continuing to strengthen Nevada's utility infrastructure to ensure reliable service and lessen our dependence on purchased power;
- Providing excellent financial performance while enhancing customer service and reliability, and;
- Establishing stronger relationships with customers, regulators, and the community at large.

Throughout 2003, our skilled and experienced workforces at Nevada Power Company and Sierra Pacific Power Company demonstrated time and again that they are capable of meeting these challenges despite the formidable business environment in which we have found ourselves. Let me briefly review the past year.

2003 FINANCIAL RESULTS

Although our financial results are still less than satisfactory, they were significantly improved over 2002. Due to after-tax write-offs of approximately $150 million in 2003, including the disallowance by the Public Utilities Commission of Nevada (PUCN) of $91 million in deferred energy costs incurred by Nevada Power and Sierra Pacific Power, Sierra Pacific Resources reported a net loss for 2003 of $140.5 million, or $1.21 per share of common stock compared with a net loss for 2002 of $307.5 million, or $3.01 per share of common stock. (For a detailed discussion of financial results, see Management's Discussion and Analysis of Financial Condition and Results of Operations section and Financial Tables beginning at page 4 of this report.)

Customer growth at Nevada Power and Sierra Pacific Power remains strong. For the 17th consecutive year, Nevada was the fastest-growing state in the U.S. Our Nevada Power Company subsidiary installed more than 40,000 new electric meters—an all-time record—principally in the Las Vegas area. Our peak electricity demand in southern Nevada has grown an average of 4.5 percent annually over the past five years, reaching a record high of 4,808 megawatts on July 22, 2003.

In northern Nevada and the Lake Tahoe region of California, our Sierra Pacific Power Company subsidiary added a record 10,000 electric meters in 2003, and peak electricity demand has grown an average of 3.1 percent annually over the past five years. Sierra Pacific Power also set an all-time peak demand record in 2003, reaching 1,657 megawatts on July 30. Growth by Sierra Pacific Power's natural gas business in the Reno-Sparks area remains strong with the total gas customer meter count increasing by over 5,000 to approximately 129,000 meters by year-end 2003.

Although the diminished credit ratings we received in 2002 following our energy cost disallowances have created challenges to accessing capital and energy markets, Sierra Pacific successfully refinanced debt due in 2003 and secured energy supplies needed to serve our utility customers.

Because of improvements in our financial condition and financial practices, the PUCN lifted a regulatory restriction that had prevented Nevada Power from paying dividends to the parent company.

While media attention has often been focused on the company's legal and regulatory activities, I want to reemphasize that we pay careful attention to the important tasks necessary to ensure that our customers enjoy reliable service and stable rates.

A step in that direction was taken in November 2003 when the PUCN voted unanimously to approve Nevada Power's Integrated Resource Plan, a comprehensive blueprint for satisfying the increasing demand for energy in southern Nevada. Among the supply solutions in the plan are construction of two new power plants comprising an additional 600 megawatts of gas-fired generation near Las Vegas by 2007.

The PUCN order granted Nevada Power authorization to negotiate purchased power contracts to fill much of the remaining capacity requirements expected for 2004–2006, along with the authority to execute agreements necessary for compliance with Nevada's new renewable energy portfolio standards.

In the meantime, Nevada Power is strengthening the "backbone" of southern Nevada's electric system with the Centennial Plan, a network of about 100 miles of new and upgraded transmission lines that will be able to deliver approximately 3,000 megawatts of electricity. The project is about two-thirds complete with full completion anticipated in January 2007.

In northern Nevada, the 180-mile Falcon to Gonder electric transmission project now under construction will give Sierra Pacific Power the capability to import an additional 260 megawatts of power at the Nevada-Utah border. That project is expected to be on line by the start of this coming summer.

We are continuing to seek opportunities to reduce operating costs throughout our organization. This includes pushing down the costs of installing new electric and natural gas service connections at Nevada Power and Sierra Pacific Power, streamlining business office procedures, and implementing new technologies to save time and further reduce costs.

For example, at Sierra Pacific Power we are eliminating certain commercial office functions at five locations in northern Nevada and in the Lake Tahoe area of California during the first half of 2004. Although the offices will be closed to walk-in service, field crews will remain assigned to these locations to maintain facilities, and customers can still conveniently conduct business with us by telephone, over the Internet and at alternative locations.

We also are making improvements in customer satisfaction. Based on the latest surveys by J.D. Power and Associates and by separate surveys conducted by an independent national firm at our request, customer satisfaction has been steadily improving.

REGULATORY MATTERS

On March 24, 2004, the PUCN issued decisions on Nevada Power's most recent general and deferred energy rate cases. The PUCN approved an approximate $45 million rate increase in Nevada Power's general rates, a $90 million rate increase for recovery of fuel and purchased power costs incurred between October 1, 2002, and September 30, 2003, and about $80 million in going forward fuel and purchased power rates and energy conservation programs. In the general rate case decision, the PUCN set Nevada Power's return on equity at 10.25 percent.

In the general rate case for Sierra Pacific Power, we are seeking an increase in annual electric revenues of approximately $88 million for recovery of over $200 million invested over the past two years in new facilities in northern Nevada. The utility's deferred energy rate case filing is for recovery of $42 million in fuel and purchased power costs, but, if approved, it will not result in a net change in customer rates due to an earlier scheduled rate decrease.

We are also asking state regulators to approve a higher authorized return on equity at Sierra Pacific Power as part of the general rate case filing. Hearings on Sierra Pacific Power's general rate case will begin in April 2004.

To ease the financial impact of higher rates on our customers, we asked the PUCN to permit us to phase in rate increases for customers of both utilities over multi-year periods.

UPDATE ON LEGAL ISSUES

While we are eager to conclude ongoing court cases and concentrate fully on running our utility businesses, the power contract termination claim filed by the bankrupt energy trading company, Enron, remains on our agenda.

In August, the New York bankruptcy court presiding over the Enron bankruptcy ruled that Nevada Power and Sierra Pacific Power must pay approximately $235 million and $103 million, respectively, to Enron for power not delivered to us under the power supply contracts terminated by Enron in May 2002. At our request, the bankruptcy court judge granted a stay of execution pending appeal. We have appealed the bankruptcy court's decision to the United States District Court and have filed a new complaint at the Federal Energy Regulatory Commission to prevent Enron from enforcing any right to collect these termination payments. (For a detailed discussion of legal matters, see Management's Discussion and Analysis of Financial Condition and Results of Operations beginning on page 4 of this report.)

In closing, I want to comment on and reaffirm a number of developments during the past year that are of paramount importance to our company's future.

- State government officials and regulators have made public statements indicating that they understand the importance of a healthy utility infrastructure and how this is critical to Nevada's continued economic well-being.
- The business strategies we have implemented are succeeding due to the outstanding efforts of our employees, especially those who do the day-to-day tasks required to keep Nevada's lights burning brightly and to help the state's economy thrive.
- We are aware of our responsibilities to the communities we serve, and we are dedicated to providing important support through charitable giving, employee volunteerism and active participation in community events.
- And, finally, we are working and concentrating hard on restoring shareholder value.

We are optimistic about your company's direction and, on behalf of the Board of Directors, the management team and employees of Sierra Pacific Resources, I want to thank you for your patience and support during these challenging times.

Walter M. Higgins
Chairman, President and Chief Executive Officer
March 25, 2004

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

Forward-Looking Statements and Risk Factors

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 the judgment entered by the Bankruptcy Court overseeing Enron's bankruptcy proceeding in favor of Enron for payments allegedly due under terminated purchased power contracts, or to provide additional cash collateral for the judgment pending appeal;

(2) unfavorable rulings in rate cases filed and to be filed by NPC and SPPC (the Utilities) with the Public Utilities Commission of Nevada (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 costs recorded by SPPC for its gas distribution business;

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

(4) whether the Utilities will be able to continue to pay SPR dividends under the terms of their respective financing agreements, the Enron Bankruptcy Court's order, their regulatory order, 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 suppliers, other than Enron, which have terminated their power supply contracts with NPC and/or SPPC will be successful in pursuing their claims against the Utilities for liquidated damages under their power supply contracts;

(6) whether the PUCN will issue favorable orders in a timely manner to permit the Utilities to borrow money and issue additional securities to finance the Utilities' operations, and to purchase power and fuel necessary to serve their respective customers, and to repay maturing debt;

(7) whether SPR, NPC, and SPPC will be able to maintain sufficient stability with respect to their liquidity and relationships with suppliers to be able to continue to operate outside of bankruptcy;

(8) whether current suppliers of purchased power, natural gas or fuel to the Utilities will continue to do business with the Utilities or will terminate their contracts, particularly in the event of a ratings downgrade, and whether the Utilities will have sufficient liquidity to pay their respective power requirements if their current suppliers continue to require the Utilities to make pre-payments or more frequent payments on their power purchases;

(9) whether the Utilities will need to purchase additional power on the spot market to meet unanticipated power demands (for example, due to unseasonably hot weather) and whether suppliers will be willing to sell such power to the Utilities in light of their weakened financial condition;

(10) whether SPPC will be successful in obtaining PUCN approval to recover the costs of the gasifier facility at the Piñon Pine Power Project in a current or future general rate case;

(11) whether the Utilities will be successful in obtaining PUCN approval to recover goodwill and other merger costs recorded in connection with the 1999 merger between SPR and NPC in a current or future general rate case;

(12) 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;

(13) 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;

(14) whether the Utilities will be able, either through appeals of the Federal Energy Regulatory Commission (FERC) proceedings or negotiation, to obtain lower prices on the long-term purchased power contracts that they entered into during 2000 and 2001 that are priced above current market prices for electricity;

(15) 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;

(16) 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;

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

(18) the loss of any significant customers;

(19) 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;

(20) 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;

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

(22) future economic conditions, including inflation or deflation rates and monetary policy;

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

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

(25) employee workforce factors, including changes in collective bargaining unit agreements, 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
- For each of SPR, NPC, and SPPC:
    - Results of Operations
    - Analysis of Cash Flows
    - Liquidity and Capital Resources
- Energy Supply (Utilities)
- Regulation and Rate Proceedings (Utilities)
- Recent Pronouncements

SPR's Utilities operate three regulated business segments which are NPC electric, SPPC electric, and SPPC natural gas service. Both Utilities provide electric service, and SPPC provides natural gas service. 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.

Overview of Major Factors Affecting Results of Operations

During 2003, SPR incurred a loss applicable to common stock of approximately $141 million compared to approximately $308 million loss applicable to common stock for the year ending 2002. SPR's consolidated loss was primarily due to a number of charges including (before income taxes):

- an unrealized net loss of $46.1 million on the derivative instrument associated with the issuance of $300 million of convertible debt. This unrealized loss had no effect on cash flows;
- the write-off of approximately $91 million of disallowed deferred energy costs, excluding carrying charges (approximately $46 million by NPC and approximately $45 million by SPPC);
- higher interest costs at SPR, NPC, and SPPC, including $52 million of interest charges recorded as a result of the Enron litigation (see Note 15 of Notes to Financial Statements, Commitments and Contingencies, for further information);
- losses by SPR subsidiaries due to the recognition of asset impairments and business disposals of $32.9 million and $9.6 million by Sierra Pacific Communications and e·three, respectively; and
- higher operating expenses that included increased reserves for uncollectible accounts and costs associated with collections for NPC and SPPC (see Other (Income) Expense analysis).

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

SPR's operating results for the year ended December 31, 2002 were negatively affected by the write-off of $434.1 million and $53.1 million of disallowed deferred energy costs by NPC and SPPC, respectively.

Significant Uncertainties

Our financial outlook is subject to significant legal, financial, and regulatory uncertainties, including:

- whether there will be any further requirements to pay the judgment of the Bankruptcy Court overseeing Enron's bankruptcy proceeding in favor of Enron or to provide further cash collateral to secure the stay of the judgment against the Utilities pending further appeal;
- whether the Utilities will have sufficient liquidity and the ability under certain restrictions to provide dividends to SPR;
- whether SPR and the Utilities will be able to successfully refinance maturing long-term debt and secure additional liquidity necessary to support their operations, including the purchase of fuel and power; and
- whether the Utilities will be able to recover regulatory assets in their current and future rate cases, especially previously incurred deferred fuel and purchased power costs, and to provide sufficient revenues to support their operations.

These uncertainties are discussed in more detail below.

Enron Litigation

As further discussed in Note 15, Commitments and Contingencies, in June 2002, Enron filed a complaint with the United States Bankruptcy Court for the Southern District of New York (the "Bankruptcy Court") against NPC and SPPC seeking to recover liquidated damages for power supply contracts terminated by Enron in May 2002. 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 agreements with the Utilities. The Judgment requires 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.

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 $281,695 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 their $235 million General and Refunding Mortgage Bond, Series H and $103 million General and Refunding Mortgage Bond, Series E, respectively, into escrow along with the required cash deposits 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. NPC and SPPC 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 their deferred energy rate cases. A hearing has been scheduled for April 5, 2004, in front of the Bankruptcy Court to review the Utilities' abilities to provide additional cash collateral which, if required, would reduce the principal amount of the General and Refunding Mortgage Bonds held in escrow by a like amount.

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 their appeal, the Utilities seek reversal of the Judgment and contend that Enron is not entitled to recover termination charges under the contract 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. The Utilities filed their principal brief on December 30, 2003 and Enron filed its cross-appeal brief and reply brief on January 30, 2004. The Utilities filed a reply brief on March 1, 2004 and also filed a motion for judicial notice and to supplement the record. Enron filed a reply brief, pertaining solely to interest issues, on March 11, 2004. On March 15, 2004, Enron filed an opposition to the motion for judicial notice and to supplement the record and an accompanying motion to strike the Utilities' reply brief. The Utilities and Enron have entered into an agreement, subject to the U.S. District Court's approval, providing the Utilities until April 12, 2004 to respond to Enron's opposition and motion, and providing Enron two weeks after receipt of any such response in which to reply. The U.S. District Court could render an opinion any time after the submission of the Utilities' response and any Enron reply. The Utilities are unable to predict the outcome of their appeal of the Judgment.

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. The PUCN ruled that "...paying into escrow while pursuing an appeal of the Bankruptcy Court's judgment and other relief does not yet provide the circumstances of experiencing a cost which can trigger a filing seeking collection from its customers, and because the issues are not ripe, this Petition is not the docket to decide whether recovery of termination payments should be sought through a general rate case or a deferred energy proceeding."

We currently do not know whether there will be any further requirement to pay the Judgment or to provide further cash collateral to secure the stay of the judgment against the Utilities pending further appeal. Further, it is uncertain how the court will rule in the pending appeal of the Judgment and if there is an adverse decision in the appeal, whether the Judgment would continue to be stayed pending further appeal. See Note 15 of Notes to Financial Statements, Commitments and Contingencies, for further information regarding the Enron litigation.

Liquidity and Financing Matters

NPC anticipates capital requirements for construction costs in 2004 will be approximately $381 million which NPC expects to finance with internally generated funds, including the recovery of deferred energy costs. NPC has $130 million of long-term debt maturing on April 15, 2004. NPC currently expects to refinance all of this debt prior to maturity through the issuance and sale of its General and Refunding Mortgage Securities.

SPPC anticipates capital requirements for construction costs during 2004 totaling approximately $107 million, which SPPC expects to finance with internally generated funds, including the recovery of deferred energy costs. SPPC has $80 million of long-term debt that it will be required to remarket or purchase by May 3, 2004.

Due primarily to the Utilities' weakened financial conditions, the Utilities have been required to pre-pay their power purchases or make more frequent payments for power deliveries. As a result of unseasonably cool weather during the spring of 2003 and its prepayment and more frequent payment obligations for its summer 2003 power requirements, NPC's liquidity was significantly constrained during the early summer months of 2003. Consequently, on June 30, 2003, NPC entered into a $60 million revolving Credit Agreement to provide additional liquidity to NPC for its summer 2003 power purchases. An increase in natural gas prices during SPPC's winter 2003-2004 peak season negatively impacted SPPC's cash flows, which SPPC addressed by issuing and selling its short-term $25 million Series F General and Refunding Mortgage Notes due March 31, 2004. In addition, SPPC entered into a $22 million short-term revolving Credit Agreement which expires March 31, 2004 to provide it with back-up liquidity during this winter peak season.

NPC anticipates that based upon its current cash balances and expected cash flows leading up to the summer 2004 season, NPC will need additional liquidity at the onset of the summer 2004 season to support its power purchases. Currently, management believes that NPC will be able to enter into financings and/or credit facilities to meet its summer 2004 cash needs.

SPPC anticipates that based upon its current cash balance and expected cash flows leading up to the summer 2004 peak season, SPPC will not need additional liquidity to support its power and natural gas purchases. Currently, SPPC is exploring the possibility of taking advantage of favorable conditions in the capital markets by entering into new financings to refinance existing debt on more favorable terms and to provide for additional or replacement backup liquidity facilities.

If the Utilities have to pay significantly higher than expected prices for fuel and purchased power, if their suppliers require significant changes to their current payment terms, or if they do not have sufficient available liquidity to obtain fuel, purchased power and, for SPPC, natural gas, the Utilities may be required to issue or incur additional indebtedness, enter into additional liquidity facilities or utilize their receivables purchase facilities. If they are unable to enter into financings to provide them with sufficient additional liquidity and to repay their maturing indebtedness, whether due to unfavorable conditions in the capital markets, lack of regulatory authority to issue or incur such debt, credit downgrades by either Standard and Poor's Rating Group, Inc. (S&P) or Moody's Investors Service, Inc. (Moody's) resulting from the uncertainties discussed in this section, or restrictive covenants in certain of their financing agreements (see Note 7, Short-Term Borrowings and Note 8, Long-Term Debt), their ability to provide power and fund their expected construction costs and their financial conditions and cash flows will be adversely affected.

SPR does not have any operations of its own and relies on dividends from the Utilities in order to satisfy its debt service payments. SPR, on a stand-alone basis, had cash and cash equivalents of approximately $15.4 million at December 31, 2003 and $16.7 million at January 31, 2004. SPR has approximately $5.4 million of debt service obligations on its existing debt securities payable during the first quarter of 2004, not including approximately $10.9 million of debt service obligations previously provided for (discussed below), and a total of $70 million of debt service obligations payable during 2004. $22 million of SPR's debt service obligations in 2004, which relate to SPR's 7.25% Convertible Notes due 2010, have been previously provided for through the pledge of U.S. government securities with the trustee at the time the Convertible Notes were issued. See Note 8, Long-Term Debt. Therefore, approximately $48 million of debt service payment requirements will need to be funded through dividends from the Utilities. Currently, SPR expects to meet its remaining debt service obligations for 2004 through the payment of dividends by the Utilities to SPR. In the event that NPC or SPPC is unable to pay dividends to SPR, SPR's liquidity and cash flows would be adversely impacted. See Note 10, Dividend Restrictions for a discussion of the dividend restrictions applicable to the Utilities.

Regulatory

Regulatory uncertainties including the outcome of pending and future regulatory filings may have a significant effect on our financial prospects.

NPC filed its biennial General Rate Case on October 1, 2003. NPC has requested a $133 million increase in the revenue requirement for general rates. Specifically, NPC requested that a $50 million (computed on an annual revenue basis) or 3.4% rate increase commence on April 1, 2004 and continue for nine months. Beginning January 1, 2005, annualized general revenue would then increase by $92 million plus the amount necessary to return $76 million (the estimated amount being deferred (plus interest) during the prior nine month period) over the following 15 months. Various interveners recommended reductions to NPC's request including lower rates for NPC's return on equity ranging from 8.10% to 10.71%, disallowance of certain costs including merger related costs and goodwill, changes to amortizations of regulatory assets, exclusion of certain plant and other assets, etc. The interveners have also recommended a range

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

of decreases and increases to NPC's general rates ranging from $1 million in reduced general rates to $17 million in increased general rates as compared to NPC's requested increase of $133 million. During the course of hearings, NPC agreed to approximately $18 million in reductions to its request for various items.

On November 14, 2003, NPC filed an application with the PUCN seeking repayment for fuel and purchased power costs accumulated between October 1, 2002 and September 30, 2003. The application sought to establish a rate to collect accumulated costs of $93 million, together with a carrying charge, to be recovered based on an asymmetric amortization that would result in the recovery of $14 million in the first year and $39.5 million in each of the next two years. The application also requested an increase to the going-forward rate for energy. In their testimony, various interveners recommended proposed disallowances from $23 million to $39 million, as well as reductions and changes to deferred rates proposed to recover costs of NPC's current and prior deferred energy rate cases, and disagreed with NPC's proposal to gross-up the equity portion of carrying charges for income taxes.

On December 1, 2003, SPPC filed an application with the PUCN seeking an electric general rate increase. In the filing, SPPC requested an increase in its general rates charged to all classes of electric customers, which were designed to produce an increase in annual electric revenues of approximately $88 million. Similar to NPC, SPPC is also asking for a staggered implementation of the overall revenue requirement. If approved, SPPC would recover $70 million of the $95 million request in the first year beginning mid-July 2004, delaying the other $25 million, plus a carrying charge, until the next year.

On January 14, 2004, SPPC filed an application with the PUCN seeking to clear approximately $42 million of deferred balances for fuel and purchased power costs accumulated between December 1, 2002, and November 30, 2003. The application requests an asymmetric amortization of the deferred energy balance that would result in recovery of $8 million in the first year, effective mid-July 2004, and $17 million for each of the two years thereafter. The request for resetting the Base Tariff Energy Rate would result in no change to the currently effective rate.

The PUCN is expected to issue orders with respect to NPC's general and deferred rate cases in late March 2004, SPPC's general rate case in May 2004 and SPPC's deferred rate case in July 2004. Management believes that they have satisfied the requirements necessary to increase the general rates as requested and that fuel and purchased power costs have been prudently incurred; however, management cannot predict the outcome of these proceedings. Material disallowances of deferred energy costs or inadequate base rates would have a significant adverse effect on NPC's and SPPC's financial conditions and future results of operations, could cause additional downgrades of their securities by the rating agencies and make it significantly more difficult to finance operations and to buy fuel and purchased power from third parties. See Note 2 of Notes to Financial Statements, Liquidity Matters and Management's Plans, Regulatory Matters for further discussion.

Business Strategies

SPR and the Utilities are addressing the uncertainties discussed above by focusing on the following business strategies:

Enron Litigation

The Utilities are appealing the judgment of the Enron Bankruptcy Court to the U.S. District Court of the Southern District of New York. In addition, they continue to pursue their Federal Energy Regulatory Commission (FERC) Section 206 complaint against Enron. In the event the Utilities were to lose the pending appeal, management currently anticipates that the Utilities would file an appeal in the U.S. Court of Appeals for the Second Circuit and request that a stay be granted pending the second appeal. In connection with any subsequent appeal of the Judgment, the Utilities currently anticipate that they will assert that because of the full protection afforded Enron by the existing collateral, a further stay is warranted, without any material change to the collateral; however, there can be no assurances that either the U.S. District Court for the Southern District of New York or the U.S. Court of Appeals for the Second Circuit would accept NPC's $235 million General and Refunding Mortgage Bond, Series H and SPPC's $103 million General and Refunding Mortgage Bond, Series E (collectively referred to as the Bonds) as sufficient collateral to support a stay of the Judgment pending further appeal.

Although management believes that the stay of execution of the Judgment will be continued during the appeal process and no significant change will be made to the requirement to post cash collateral, management believes that through financial arrangements currently being negotiated, the Utilities would have the means to meet a substantial payment obligation on the Judgment. The Utilities expect to enter into a Remarketing Agreement with Enron and one or more investment banks as Remarketing Agent(s) to provide for the remarketing of the Bonds which are presently held in escrow. Although the terms of such a remarketing agreement are not final, management believes that the form of the final agreement will facilitate the successful remarketing of the Bonds to satisfy the Utilities' payment obligations with respect to the Judgment. The Remarketing Agreement will allow Enron, at its option, to require the initiation of a remarketing process with respect to the Bonds and will contain certain provisions that will provide the Utilities with flexibility to modify the terms of the Bonds to attempt a successful initial remarketing effort at the lowest possible interest rate to be determined by the Remarketing Agent(s).

If the Utilities are unsuccessful in the remarketing of the Bonds or if Enron chooses not to have the Bonds remarketed, the Bonds would, from that point forward, accrue interest at 14% and mature in one year; however, Enron would have the right, at any time prior to maturity, to require that the Utilities redeem their bonds at par within four business days. Under the terms of the escrow arrangement between the Utilities and Enron, prior to taking possession of the Bonds, Enron would be required to release the Utilities from any and all payment obligations with respect to the Judgment. In the event that the Bonds are not remarketed, there can be no assurance that the Utilities will have available cash or liquidity facilities in place to provide for the payment of the Bonds.

If the appeal process is unsuccessful and the Judgment is ultimately paid, the Utilities plan to pursue recovery of the amounts paid through future deferred energy filings. Determination of the amount of recovery through rates, if any, will be made through the Utilities' usual regulatory process. There is no assurance that the PUCN will allow recovery of any amounts ultimately paid to Enron.

Liquidity and Financing Matters

Based on current market conditions and the history of market access since the credit rating downgrades, management believes that they will be able to successfully refinance the $130 million of NPC's 6.20% Series B, Senior Notes due 2004 maturing on April 15, 2004. Management also believes SPPC will be able to successfully remarket the $80 million of Water Facility Refunding Revenue Bonds prior to May 1, 2004. Management is also giving consideration to obtaining additional funding that would provide for certain amounts of working capital facilities as well as potentially refunding certain debt obligations due in 2005.

On January 21, 2004, NPC filed an application with the PUCN for authority to issue secured long-term debt in an aggregate amount not to exceed $230 million through the period ending December 31, 2004. This authority was requested to allow for the refinancing of NPC's $130 million 6.20% Series B Senior Notes due 2004, as well as to provide an additional $100 million of liquidity to support utility operations.

On October 9, 2003, NPC filed an application with the PUCN for authority to issue secured or unsecured short-term debt securities in an aggregate amount not to exceed $250 million through the period ending December 31, 2005. This authority was requested to replace the existing short-term debt authority that expired on December 31, 2003. On December 17, 2003, the PUCN issued an order granting NPC the authority to issue up to $250 million in short-term secured or unsecured debt securities. This authority expires December 31, 2005.

Currently, management believes that NPC will be able to enter into financings and/or credit facilities to meet its summer 2004 cash needs. Alternatively, NPC may draw on its accounts receivable facility for additional liquidity. Actual amounts that may be advanced under the receivables purchase facility will vary significantly depending upon, among other things, the time of year, the weather conditions and the delinquency rates of NPC's receivables. Based on 2003 accounts receivables and the variables discussed above, NPC had a maximum capacity of $82 million and minimum capacity of $32 million under the receivables facility. If NPC does not have sufficient liquidity to meet its power requirements, particularly at the onset of the 2004 summer season, NPC may be required to issue or incur additional indebtedness.

On October 9, 2003, SPPC filed an application with the PUCN for authority to issue secured or unsecured short-term debt securities in an aggregate amount not to exceed $250 million through the period ending December 31, 2005. This authority was requested to replace the existing short-term debt authority that expired on December 31, 2003. On December 17, 2003, the PUCN issued an order granting SPPC the authority to issue up to $250 million in short-term secured or unsecured debt securities. This short-term debt authority will expire December 31, 2005.

On December 31, 2003, SPPC filed an application with the PUCN for authority to issue secured long-term debt in an aggregate amount not to exceed $230 million through the period ending December 31, 2004. This authority was requested to allow for the refinancing and remarketing of existing debt securities, as well as to provide additional liquidity to support utility operations.

Currently, management believes that SPPC will be able to internally generate sufficient cash to meets its power procurement cash needs. Alternatively, management believes that SPPC will be able to enter into financings and/or credit facilities or, if necessary, may draw on its accounts receivable facility for additional liquidity. Actual amounts that may be advanced under the receivables purchase facility will vary significantly depending upon, among other things, the time of year, the weather conditions, and the delinquency rates of SPPC's receivables. Based on 2003 accounts receivables and the variables discussed above, SPPC had a maximum capacity of $28 million and minimum capacity of $13 million under the receivables facility. If SPPC does not have sufficient liquidity to meet its power requirements, SPPC may be required to issue or incur additional indebtedness.

In the PUCN order granting the Utilities each $250 million of short-term financing authority, the PUCN removed the NPC dividend restriction that had previously been in place and replaced it with a restriction limiting the total amount of dividends that could be paid by the Utilities. The PUCN limited cash dividends from NPC and SPPC to an aggregate total of $70 million per year from NPC and/or SPPC to SPR until December 31, 2005.

Moreover, in February 2004, NPC amended the dividend restriction contained 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. As amended, NPC does not anticipate that the First Mortgage Indenture dividend restriction will materially limit the amount of dividends that it may pay to SPR in the foreseeable future.

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 dividend an aggregate $48 million to SPR, which is the amount needed in order for SPR to meet its debt service requirements for 2004.

Regulatory

The Utilities have worked diligently to improve their relationships with the PUCN, including undertaking steps to address prior concerns the PUCN expressed in connection with the March 2002 deferred fuel disallowance. In addition to working closely with the staff of the PUCN to keep them apprised of developments and proactively address any potential concerns, the Utilities continue to work closely with the PUCN in implementing new energy risk management and fuel procurement polices, which are designed to stabilize the Utilities' risk exposure in the energy market.

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

The Utilities' long-term integrated resource plans 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 resource plan was filed with the PUCN on July 1, 2003 and was approved in November 2003. SPPC expects to file its plan in July 2004. The Utilities are required to seek PUCN approval for power purchases with terms of three years or more.

Additionally, the Utilities also seek regulatory input and acknowledgement of intermediate term energy supply plans and resource procurement with a one to three year planning horizon. Management believes this is necessary to ensure that the appropriate levels of risks are being mitigated at reasonable costs and are being retained in the portfolio, and decisions to manage risks with the best available information at the point in time when decisions are made are subject to reasonable mechanisms for rate recovery. NPC's energy supply plan was filed with the PUCN on July 1, 2003 with its 2003-2022 resource plan. The resource plan, including NPC's recommended natural gas hedging strategy, was approved by the PUCN on November 12, 2003. SPPC's plan is in the final stages of development and will be filed with the PUCN for informational purposes.

Our planned strategies are designed to mitigate the risks related to the foregoing uncertainties. However, as discussed in SPR's liquidity discussion, if the uncertainties discussed above are resolved adversely to the Utilities, SPR would likely experience one-time charges that would offset in whole or in part SPR's earnings and gains and could result in significant losses to SPR. Because of the relationships among the uncertainties described above, an adverse development with respect to a combination of these uncertainties, could have a material adverse effect on SPR's, NPC's and SPPC's financial condition, liquidity, and could make it difficult for the Companies to continue to operate outside of bankruptcy. See Note 2 of Notes to Financial Statements, Liquidity Matters and Management's Plans, for additional information regarding the significant uncertainties facing SPR and the Utilities and Management's plans to address those uncertainties.

CRITICAL ACCOUNTING POLICIES

The following items represent critical accounting policies 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 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 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 of Notes to Financial Statements, Summary of Significant Accounting Policies, 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, Accounting for Generation Divestiture Costs, Disposal of and Impairment of Long-Lived Assets, and Accounting for Derivatives and Hedging Activities, all of which are discussed immediately below.

Deferred Energy Accounting

On April 18, 2001, the Governor of Nevada signed into law Assembly Bill 369 (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, 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. AB 369 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, AB 369 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 AB 369 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 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 Regulation and Rate Proceedings, Nevada Matters, 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 of $93 million. Management believes all these costs were incurred prudently. However in NPC's 2002 and 2001 deferred energy cases, the PUCN disallowed $48.1 million and $434 million of the $195.7 million and $922 million requested for recovery, respectively.

As described in more detail under Regulation and Rate Proceedings, Nevada Matters, on January 14, 2004, SPPC filed an application with the PUCN seeking repayment for purchased fuel and power costs accumulated between December 1, 2002 and November 30, 2002 of $42 million. Management believes all these costs were incurred prudently. However, in SPPC's 2003 deferred energy case, the PUCN disallowed $15.4 million for purchased fuel and power costs and required SPPC to repay customers approximately $29.6 million. This resulted in a write-off of $45 million. Furthermore, in SPPC's 2002 deferred energy case, the PUCN disallowed $53 million of the $205 million requested for recovery.

See Regulation and Rate Proceedings, later, for additional discussion of the regulatory process underway to recover these deferred costs.

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 instructs the Utilities to propose an amortization period for the merger related costs and allows 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 December 31, 2003. The deferred other merger costs consist 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 October 1, 2003, and December 1, 2003, NPC and SPPC, respectively, filed applications with the PUCN for general rate increases that included, among other items, requests to recover deferred merger costs, including goodwill based on management's belief that merger savings exceeded goodwill and merger costs. The extent to which goodwill and merger costs will be recovered in future revenues and the timing of those recoveries will be determined in the spring of 2004 in the PUCN decision on NPC's and SPPC's current general rate case. Any portion of merger costs that the Utilities are not permitted to recover in future rates will have to be charged to operating expense in 2004. Furthermore, a decision by the PUCN to disallow any portion of goodwill may result in an impairment of goodwill, under the provisions of SFAS No. 142, "Goodwill and Other Intangible Assets."

To determine the extent, if any, goodwill would be impaired as a result of a negative decision by the PUCN, management evaluated goodwill for impairment assuming no recovery in rates as of December 31, 2003. Based on our preliminary calculations, to the extent that the Utilities are not permitted to recover any portion of goodwill in future rates, management does not believe that an impairment charge will be required. However, the $19.1 million included in other regulatory assets would be a charge to earnings to the extent of the disallowance as this amount would have been charged to earnings previously if not for the provisions of SFAS No. 71. As a result SFAS No. 142 would not apply to this portion.

As part of our analysis, we computed the fair value as the sum of the discounted expected future cash flows without interest charges. We determined that the fair value of each of the reporting units, NPC, SPPC—Electric and SPPC—Gas, exceeded the carrying value including goodwill; accordingly we believe no impairment would be necessary to the extent goodwill is disallowed by the PUCN.

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

However, 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 Generation Divestiture Costs

As a condition to its approval of the merger between SPR and NPC, the Utilities filed, and in February 2000 the PUCN approved, a revised Divestiture Plan stipulation for the sale of the Utilities' generation assets. In May 2000, an agreement was announced for the sale of NPC's 14% undivided interest in the Mohave Generating Station (Mohave). In the fourth quarter of 2000, the Utilities announced agreements to sell six additional bundles of generation assets described in the approved Divestiture Plan. The sales were subject to approval and review by various regulatory agencies.

AB 369, which was signed into law on April 18, 2001, prohibited the sale of generation assets until July 2003 and directed the PUCN to vacate any of its orders that had previously approved generation divestiture transactions. In January 2001, California enacted a law that prohibits any further divestiture of generation properties by California utilities until 2006, including SPPC, and could also affect any sale of NPC's interest in Mohave since the majority owner of that project is Southern California Edison (SCE). SPPC's request for an exemption from the requirements of a separate California law requiring approval of the CPUC to divest its plants was denied.

The sales agreements for the six bundles provided that they would terminate eighteen months after their execution and all of the agreements have now terminated in accordance with their respective provisions. As of December 31, 2003, NPC and SPPC had incurred costs, including carrying charges, of approximately $21.9 million and $13.3 million, respectively, in order to prepare for the sale of generation assets. In the fourth quarter of 2001, each Utility requested recovery of its respective costs in its application for a general rate increase filed with the PUCN. In 2002, the PUCN delayed recovery of divestiture costs to future rate case requests and granted a carrying charge on the costs until such time as recovery is allowed. On October 1, 2003, and December 1, 2003, NPC and SPPC, respectively, filed general rate case applications that included requests for the recovery of divestiture costs in future rates. The PUCN is expected to rule on these applications in the spring of 2004. To the extent that the Utilities are not permitted to recover any portion of these costs in future rates, the disallowed costs and related carrying charges would be required to be written off in that period's earnings.

Disposal of and Impairment of Long-Lived Assets

SPR and the Utilities evaluate their Utility Plant and definite-lived tangible assets for impairment whenever indicators of impairment exist. Accounting standards require that if the sum of the undiscounted expected future cash flows from a company's asset (without interest charges that will be recognized as expenses when incurred) is less than the carrying value of the asset, an asset impairment must be recognized in the financial statements. The amount of impairment recognized is calculated by subtracting the fair value of the asset from the carrying value of the asset. The financial statements of SPR and the Utilities include long-lived assets for which we have assessed the application of these provisions.

Sierra Pacific Communications

As discussed in Note 19, Discontinued Operations and Disposal and Impairment of Long-Lived Assets, Sierra Pacific Communication (SPC) operates its telecommunication business in two segments, Metropolitan Area Network and Long Haul Fiber Network. SPC evaluated the assets of its business as of June 30, 2003, as a result of market conditions created by the bankruptcy of Touch America. This event substantially deteriorated the telecommunications market in the areas where SPC operates its long haul fiber assets. SPC anticipates the market for fiber optic cable and conduits will likely become significantly over-supplied which has caused Sierra Pacific Communications to test for, and as a result, recognize an impairment charge. Estimates underlying the asset impairment are significant in determining the impairment charge of $32.9 million for the twelve months ending December 31, 2003. The assumptions underlying the calculation of the undiscounted future cash flows used to evaluate the impairment, including projected revenues and expenses and the discount rate used to present value future cash flows materially effect the amount of the impairment charge. In estimating undiscounted future cash flows for its long haul fiber assets, SPC used prices for similar asset sales adjusted for the markets factors that resulted from the Touch America bankruptcy discussed above. To estimate the undiscounted cash flows from the metropolitan area network assets, SPC used revenues from current and projected sales and lease contracts and continued operating expenses over the approximate 18-year remaining life of the assets. Any difference from the assumptions used could materially change the results of the asset impairment charge as recognized.

Piñon Pine

SPPC owns a combined cycle generation facility, a post-gasification facility, and, through its wholly owned subsidiaries, a gasifier that are collectively referred to as the Piñon Pine Power Project (Piñon Pine). Construction of Piñon Pine was completed in June 1998. Included in the Consolidated Balance Sheets of SPR and SPPC is the net book value of the gasifier and related assets, which is approximately $95 million as of December 31, 2003.

To date, SPPC has not been successful in obtaining sustained operation of the gasifier. In 2001, SPPC retained an independent engineering consulting firm to complete a comprehensive study of the Piñon Pine gasification plant. After evaluating the options presented in the draft report, SPPC decided not to pursue modifications intended to make the facility operational and is seeking recovery of the experimental portion of Piñon Pine that was not previously being recovered through regulated rates in its current general rate case, filed December 1, 2003. This recovery is based, in part, on the PUCN's approval of Piñon Pine as a demonstration project in an earlier IRP. However, if SPPC is unsuccessful in obtaining recovery and the asset is deemed impaired in accordance with SFAS No. 144, "Accounting for the Impairment of Disposal of Long-Lived Assets," (SFAS No. 144) there could be a material adverse effect on SPPC's and SPR's results of operations.

Mohave

As discussed in more detail in Note 15, Commitments and Contingencies, Environmental, NPC owns a 14% interest in the Mohave Generating Station located in Laughlin, Nevada. Included in the Consolidated Balance Sheets of SPR and NPC is the net book value of NPC's share of the Mohave facility, which is approximately $40.5 million as of December 31, 2003.

Due to a lack of progress in negotiations with the parties to resolve several coal and water supply issues, SCE, the operating partner, filed an application with the CPUC to determine whether it is in the public interest to continue operation of the Mohave facility beyond 2005. Also, 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 due to the uncertainty over the coal supply and water issues.

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 approved by 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 in order to recover the remaining book value of Mohave. Alternatively, NPC requested that the PUCN authorize the transfer of the remaining book value to a regulatory asset account to be amortized over a period as determined by the PUCN. However, if NPC is unsuccessful in obtaining recovery and the asset is deemed impaired in accordance with SFAS No. 144, there could be an adverse effect on NPC's and SPR's financial position, results of operations, and future cash inflows.

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 and 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.

Debt Conversion Option

In connection with SPR's issuance of its Convertible Notes in February 2003, 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 Emerging Issues Task Force of the FASB (EITF) Issue No. 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. Changes in the fair value of the option were recognized in earnings in the period of the change.

EITF Issue No. 00-19, "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 applicable provisions of EITF Issue No. 00-19 are met. 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, which allows for SPR to choose net-cash settlement or settlement in shares upon conversion of the Convertible Notes. In accordance with EITF Issue No. 00-19, the fair value of the derivative of $118 million previously recorded in current liabilities was reclassified to equity on the date of the shareholder vote. In addition, EITF Issue No. 00-19 indicates that subsequent changes in fair value should not be recognized as long as the derivative remains classified in equity. As long as the derivative remains classified in equity, SPR will not mark this instrument to market. Accordingly, no unrealized gains or losses will be recorded in earnings subsequent to August 11, 2003. The previous changes in fair value of the derivative instrument recorded in earnings will not be reversed.

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

Based on the closing price of SPR's common stock at August 11, 2003, of $4.68 per share, the fair value of the conversion option was determined to be approximately $118 million, and as a result, SPR recorded an unrealized gain of approximately $61.5 million in the quarter ended September 30, 2003. SPR recorded a cumulative net unrealized loss of approximately $46.1 million for the twelve month period ending December 31, 2003.

From time to time, SPR and the Utilities have other non-energy related derivative instruments such as interest rate swaps. The transition adjustment related to these types of derivative instruments resulting from the adoption of SFAS No. 133 was reported as the cumulative effect of a change in accounting principle in Other Comprehensive Income. Additionally, the changes in fair values of these non-energy related derivatives are also reported in Other Comprehensive Income until the related transactions are settled or terminate, at which time the amounts are reclassified into earnings. On April 1, 2002, SPR paid $9.5 million to terminate an interest rate swap related to $200 million of SPR floating rate notes maturing April 20, 2003, of which $7.3 million was reclassified into earnings during the twelve-month period ended December 31, 2002. The remaining $1.5 million (net of tax) was reclassified into earnings during the twelve months ended December 31, 2003.

Accounting for Income Taxes

As of December 31, 2003, unutilized net operating losses (NOLs) were $276.6 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 carryforward period for NOLs incurred is 20 years, and as such the losses incurred in the years ended December 31, 2001, 2002, and 2003 will expire in 2021, 2022, and 2023, respectively. Based on expected future taxable income of SPR, the NOL is expected to be fully utilized by 2008. Accordingly, no valuation allowance has been recorded as of December 31, 2003 because it is more likely than not that the NOLs will be fully utilized.

Litigation Contingencies

Note 15, Commitments and Contingencies, in Notes to Financial Statements discusses the significant legal matters of SPR and its subsidiaries. As described in Note 15, NPC and SPPC established accrued liabilities, included in their Consolidated Balance Sheets as "Contract termination liabilities," of $280 million and $105 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 $245 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. A significant disallowance of these costs by the PUCN could have a material adverse effect on the future financial position, results of operations, and cash flows of SPR, NPC, and SPPC.

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 15, 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 13 in Notes to Financial Statements, Retirement Plan, and Postretirement Benefits, 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 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. The amounts funded are then used to meet benefit payments to plan participants. SPR contributed $72.2 million and $41.1 million to its pension plan, in 2003 and 2002, respectively, and $0.2 million to the other postretirement benefits plan in both 2003 and 2002. 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 has decreased significantly. As a result, additional contributions may be required in the future to meet the requirements of the plan to pay benefits to plan participants. SPR is expected to contribute in 2004 is $35.7 million.

Pension Plans

SPR's reported costs of providing noncontributory defined pension benefits (described in Note 13 in Notes to Financial Statements, Retirement Plan and Postretirement Benefits) 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, 2003, 2002, and 2001, SPR recorded pension benefit expense of approximately $35.5 million, $22.5 million, and $14.2 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, 2003, 2002, and 2001 were $17.7 million, $30.0 million, and $36.4 million respectively.

SPR has not made changes to pension plan provisions in 2003, 2002, and 2001 that had significant impacts on recorded pension expense. As further described in Note 13 in Notes to Financial Statements, Retirement Plan and Postretirement Benefits, SPR reduced the discount rate used in determining pension expense for the calendar year 2003 from 7.50% in 2002 to 6.75%. This change did not have a significant impact on reported pension costs for 2003.

SPR has further reduced the discount rate to 6.00% for determining the expense to be recorded in 2004. However, pension costs for 2004 are not expected to increase significantly as a result of this change in the discount rate, because of expected improvements in market value of the plan assets and 2003 contributions by SPR.

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 regarding current discount rates and 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 benefit obligation (PBO) and the reported annual pension cost on the income statement (PC) 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%	$(55.2)	$(7.2)
Rate of return on plan assets	1%	N/A	$(2.5)

In selecting an assumed discount rate, SPR considered the yield on high quality bonds as measured by Moody's Investors Service, Inc. (Moody's) Aa composite bond index.

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 $58 million in 2003 compared to a $23.1 million loss in 2002 as a result of improved market conditions in 2003.

As a result of SPR's plan asset returns and funding through September 30, 2003, SPR was able to recognize a reduction in the additional minimum liability in the amount of $26.2 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 2003. The remaining charge to Accumulated Other Comprehensive Income will be restored through common equity in future periods to the extent the fair value of trust assets exceeds the accumulated benefit obligation.

Other Postretirement Benefits

SPR's reported costs of providing other postretirement benefits (described in Note 13 in Notes to Financial Statements, Retirement Plan and Postretirement Benefits) are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience.

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

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, 2003, 2002, and 2001, SPR recorded other postretirement benefit expense of approximately $11.4 million, $3.1 million, and $2.5 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, 2003, and 2002, were $7.1 million and $6.9 million, respectively.

SPR has not made changes to other postretirement benefit plan provisions in 2003, 2002, and 2001 that have had any significant impact on recorded benefit plan amounts. As further described in Note 13 in Notes to Financial Statements, Retirement Plan and Postretirement Benefits, SPR has revised the discount rate in 2003, as compared to 2002, from 7.50% to 6.75%. This change did not have a significant impact on reported other postretirement benefit costs in 2003. SPR has further reduced the discount rate to 6.00% for determining the expense to be recorded in 2004. 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 on the income statement (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 APBO Increase/ (Decrease)	Impact on PBC Increase/ (Decrease)
Discount rate	1%	$(25.6)	$(1.9)
Health Care cost trend rate	1%	$ 19.6	$ 1.0
Rate of return on plan assets	1%	N/A	$(0.5)

In selecting an assumed discount rate, SPR considered the yield on high quality bonds as measured by Moody's Aa composite bond index.

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 $9.7 million in 2003 compared to a $6.8 million loss in 2002 as a result of improved market conditions in 2003.

Asset Retirement Obligations

In June 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 provides accounting requirements for the recognition and measurement of liabilities associated with the retirement of tangible long-lived assets. Under the standard, these liabilities will be recognized at fair value as incurred and capitalized as part of the cost of the related tangible long-lived assets. Accretion of the liabilities due to the passage of time will be an operating expense. 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. 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.

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. Although the related retirement obligation and corresponding charges recognized were immaterial to the financial statements of NPC, those amounts were based on certain estimates and assumptions. The estimated liability is based on two levels of decommissioning, minimal and full, and two possible retirement dates. The liability is escalated using average historical Consumer Price Index inflation factors equal to the estimated retirement dates. The liability is discounted using credit-adjusted risk-free rates of return for the respective retirement dates. Changes to future statements of financial position and results of operations will occur to the extent that actual results differ from the estimates and assumptions used, including changes in decommissioning costs, timing, or changes in NPC's credit rating. SPPC has no significant asset retirement obligations.

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. Management operates the transmission and distribution system as though they will be operated in perpetuity and will continue to be used or sold without land remediation. As a result, the Utilities have not recorded any costs associated with the removal of the transmission and distribution systems.

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. Accounts receivable as of December 31, 2003, include unbilled receivables of $63 million and $56 million for NPC and SPPC, respectively. Accounts receivable as of December 31, 2002, include unbilled receivables of $60 million and $63 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 $75.3 million, $71.5 million, and $55.8 million of interest costs for the twelve months ended December 31, 2003, 2002, and 2001, respectively, from the issuance of debt. The holding company's operating results for the twelve months ended December 31, 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 8, Long-Term Debt in the Notes to Financial Statements for further discussion on the Convertible Notes. The holding company's operating results for the twelve months ended December 31, 2001, also reflect a charge of $22 million in connection with SPR's terminated plans to purchase Portland General Electric Company, including approximately $7.5 million representing a termination payment for shared expenses.

Tuscarora Gas Pipeline Company

TGPC, a wholly owned subsidiary of SPR, contributed $3.9 million in net income for the twelve months ended December 31, 2003, $3.3 million in net income for the twelve months ended December 31, 2002, and $2.6 million in net income for the twelve months ended December 31, 2001.

Sierra Pacific Communications

SPC, a wholly owned subsidiary of SPR, incurred a net loss of ($25.2) million for the twelve months ended December 31, 2003, a net loss of ($5.9) million for the twelve months ended December 31, 2002, and a net loss of ($2.9) million for the twelve months ended December 31, 2001. SPC's increased loss for the twelve months 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 twelve months 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. As of December 31, 2003, management is considering the sale of SPC's business assets that consist of the Metro Area Networks in Las Vegas and Reno, Nevada. For additional information see Note 19, Discontinued Operations and Disposal and Impairment of Long-Lived Assets and Note 8, Long-Term Debt of the Notes to Financial Statements.

e·three

SPR began negotiations in the second quarter of 2003 to sell its subsidiary, e·three. Accordingly, on June 30, 2003, e·three was reported as discontinued operation. Based on the expected selling price, a pre-tax loss on the disposal of $8.9 million was recognized for the six months ended June 30, 2003. On September 26, 2003, the sale of e·three was completed. As a result of the final sales price, an additional pre-tax loss on disposal of $703,787 was recognized for the three months ended September 30, 2003. See Note 19, Discontinued Operations and Disposal and Impairment of Long-Lived Assets of the Notes to Financial Statements for additional information.

Other Subsidiaries

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

Sierra Pacific Resources (Consolidated)

During 2003, SPR incurred a loss applicable to common stock of approximately $141 million compared to an approximate $308 million loss applicable to common stock for the year ending 2002. SPR's consolidated loss was primarily due to a number of charges including (before income taxes):

- an unrealized net loss of $46.1 million on the derivative instrument associated with the issuance of $300 million of convertible debt. This unrealized loss had no effect on cash flows;
- the write-off of approximately $91 million of disallowed deferred energy costs, excluding carrying charges (approximately $46 million by NPC and approximately $45 million by SPPC);
- higher interest costs at SPR, NPC, and SPPC, including $52 million of interest charges recorded as a result of the Enron litigation (see Note 15 of Notes to Financial Statements, Commitments and Contingencies, for further information);
- losses by SPR subsidiaries due to the recognition of asset impairments and business disposals of $32.9 million and $9.6 million by Sierra Pacific Communications and e·three, respectively; and
- higher operating expenses that included increased reserves for uncollectible accounts and costs associated with collections for NPC and SPPC (see Other (Income) Expense analysis).

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

SPR's operating results for the year ended December 31, 2002 were negatively affected by the write-off of $434.1 million and $53.1 million of disallowed deferred energy costs by NPC and SPPC, respectively.

Neither SPR nor NPC paid or declared a common dividend in 2003. SPPC declared and paid a common stock dividend to its parent, SPR, during 2003 of $18.5 million. SPPC paid $3.9 million in dividends to holders of its preferred stock during 2003.

Management has identified a number of risks and uncertainties that may have a negative impact on SPR's financial condition and results of operations. These risks and uncertainties are discussed in SPR's Liquidity and Capital Resources discussion below. If certain of these risks and uncertainties are decided adversely to SPR and the Utilities, SPR would likely experience one-time charges that would offset in whole or in part SPR's earnings and gains and could result in significant losses to SPR.

ANALYSIS OF CASH FLOWS

SPR's consolidated net cash flows decreased during 2003 compared to 2002, as a result of a decrease in cash from operating activities that was offset in part by increases in cash flows from 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, higher interest costs paid in 2003 and the prepayment and accelerated payment of fuel and energy purchases during 2003. Partially offsetting these items was additional cash provided from the collection of previously deferred fuel and purchased power costs through deferred energy rate increases and lower purchased power costs during 2003. Cash flows from investing activities improved in 2003 because of reduced investments by SPR in its unregulated subsidiary, Sierra Pacific Communications 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 no common dividend payments by SPR in 2003.

SPR's consolidated net cash flows improved in 2002 compared to 2001. As a result of an increase in cash flows from operating activities offset in part by decreases in cash flows from investing and financing activities. Although SPR recorded a net loss during 2002, compared to net income in 2001, the loss in 2002 resulted largely from the write-off of disallowed deferred energy costs at the utilities for which the cash outflow had occurred in 2001. Other factors contributing to 2002's improved cash flows from operating activities include the collection of deferred energy costs from customers and lower energy prices. Also, cash flows from operating activities in 2002 reflect the receipt of an income tax refund. Cash flows from investing activities decreased in 2002 because 2001 investing activities included cash provided from the sale of the assets of SPPC's water business. Also, cash flows from investing activities decreased because of additional cash utilized for construction activities during 2002 compared to 2001. Cash flows from financing activities were lower in 2002 because of decreases in net long-term debt issued, decreases in short-term borrowings and reduced proceeds from the sale of common stock.

LIQUIDITY AND CAPITAL RESOURCES (SPR CONSOLIDATED)

SPR, on a stand-alone basis, had cash and cash equivalents of approximately $15.4 million at December 31, 2003 and $16.7 million at January 31, 2004. SPR has approximately $5.4 million of debt service obligations on its existing debt securities payable during the first quarter of 2004, not including approximately $10.9 million of debt service obligations previously provided for (discussed below), and a total of $70 million of debt service obligations payable during 2004. $22 million of SPR's debt service obligations in 2004, which relate to SPR's 7.25% Convertible Notes due 2010, have been previously provided for through the pledge of U.S. government securities with the trustee at the time the Convertible Notes were issued. See Note 8, Long-Term Debt of Notes to Financial Statements. Therefore, approximately $48 million of debt service requirements will need to be funded through dividends from the Utilities. Currently, SPR expects to meet its remaining debt service obligations for 2004 through the payment of dividends by the Utilities to SPR. In the event that NPC or SPPC is unable to pay dividends to SPR, SPR's liquidity and cash flows would be adversely impacted. See below for a discussion of the dividend restrictions applicable to the Utilities.

SPR, on a stand-alone basis, does not have any debt maturing in 2004. SPR's $300 million 8¾% Notes due 2005 will mature in May 2005. Currently, management is exploring the possibility of refinancing the $300 million of debt prior to the May 2005 maturity date in order to take advantage of favorable conditions and opportunities in the capital markets. There can be no assurances that SPR can successfully refinance such debt on favorable terms. In the event that SPR cannot refinance such debt prior to or at the time of maturity, SPR will experience a material adverse impact on its financial condition.

Management has identified a number of other uncertainties that may have a negative impact on SPR's financial condition and cash flows. The most significant of these uncertainties are:

- whether there will be any further requirements for the Utilities to pay the judgment of the Bankruptcy Court overseeing Enron's bankruptcy proceeding in favor of Enron or to provide further cash collateral, to secure the stay of the judgment against the Utilities pending further appeal;
- whether the Utilities will be able to recover regulatory assets in their current and future rate cases, especially previously incurred deferred fuel and purchased power costs, and to provide sufficient revenues to support their operations;
- whether the Utilities will have sufficient liquidity and the ability under certain restrictions to provide dividends to SPR; and
- whether SPR and the Utilities will be able to successfully refinance maturing long-term debt and secure additional liquidity necessary to support their operations, including the purchase of fuel and power.

Because of the relationships among the uncertainties described above, an adverse development with respect to a combination of these uncertainties, could have a material adverse effect on SPR's, NPC's and SPPC's financial condition, results of operations and liquidity, and could make it difficult for them to continue to operate outside of bankruptcy.

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 may impose limits on investment returns or otherwise impact the amount of dividends that the Utilities may declare and pay, and the Federal Power Act 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 Resources), 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.

- NPC's 10⅞% General and Refunding Mortgage Notes, Series E, due 2009, which were issued on October 29, 2002, NPC's 9% General and Refunding Mortgage Notes, Series G, due 2013, which were issued on August 13, 2003, and NPC's General and Refunding Mortgage Bond, Series H, which was issued December 4, 2003, limit the amount of payments in respect of common stock that NPC may pay to SPR. However, that 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 both series of Notes and the Bond also permit NPC to make payments to SPR in excess of the amounts payable discussed above in an aggregate amount not to exceed: (1) under the Series E Notes, $15 million from the date of the issuance of the Series E Notes, and (2) under the Series G Notes and the Series H Bond, $25 million from the date of the issuance of the Series G Notes and the Series H Bond, 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 Notes, the Series G Notes or the Series H Bond,
- 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, 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.

If NPC's Series E Notes, Series G 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.

- On October 29, 2002, NPC established an accounts receivable purchase facility, which was renewed on October 28, 2003, and will expire on October 26, 2004. The agreements relating to the receivables purchase facility contain various covenants, including a limitation on payments in respect of common stock by NPC to SPR that is identical to the limitation contained in NPC's General and Refunding Mortgage Notes, Series E and Series G, and NPC's General and Refunding Mortgage Bond, Series H, described above.
- 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.

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

Dividend Restrictions Applicable to Sierra Pacific Power Company

- SPPC's Term Loan Agreement dated October 30, 2002, as amended, which expires October 31, 2005, limits the amount of payments that SPPC may pay to SPR. However, that 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 PIES) provided that those payments do not exceed $90 million, $80 million, and $60 million in the aggregate for the twelve month periods ending on October 30, 2003, 2004, and 2005, respectively. SPPC's General and Refunding Mortgage Bond, Series E, General and Refunding Mortgage Notes, Series F and General and Refunding Mortgage Note, Series G, contain the same dividend restriction as the Term Loan Agreement.

  The Term Loan Agreement, the Series E Bond, the Series F Notes, and the Series G Note, also permit SPPC to make payments to SPR in an aggregate amount not to exceed $10 million during the term of the Term Loan Agreement. In addition, SPPC may make payments to SPR in excess of the amounts described above so long as, at the time of the payment and after giving effect to the payment, there are no defaults or events of default under the applicable financing agreement or security, and such amounts, when aggregated with the amount of payments to SPR by SPPC since the date of execution of the such financing agreement or securities, do not exceed the sum of:

  - 50% of SPPC's Consolidated Net Income for the period commencing January 1, 2003, and ending with last day of fiscal quarter most recently completed prior to the date of the contemplated dividend payment, plus
  - the aggregate amount of cash received by SPPC from SPR as equity contributions on its common stock during such period.

- On October 29, 2002, SPPC established an accounts receivable purchase facility, which was renewed on October 28, 2003, and expires on October 26, 2004. The agreements relating to the receivables purchase facility contain various covenants, including a limitation on the payment of dividends by SPPC to SPR that is identical to the limitation contained in SPPC's Term Loan Agreement, described above.

- 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 December 17, 2003, the PUCN issued an order in connection with its authorization of the issuance of short-term debt securities by NPC and SPPC. The PUCN order, for Dockets 03-10022 and 03-10023, permits NPC and SPPC to dividend an aggregate of $70 million per year to SPR through December 31, 2005. The PUCN order also provides that the dividend limitation may be reviewed in a subsequent application to grant short-term debt authority and that, in the event that exigent circumstances are experienced 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 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. The Utilities have the right to seek modification of the conditions of the stay if there is a material change in the facts upon which the stay order is based.

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 Term Loan Agreement and in the financing agreements that contain substantially similar terms as the Term Loan Agreement. The dividend restriction in the PUCN order is the most restrictive provision applicable to both Utilities and may be more restrictive than the individual dividend restrictions if dividends are paid from both Utilities because the $70 million PUCN dividend restriction is less than the aggregate amount of the Utilities' most restrictive individual dividend restrictions.

Effects of Rate Case Decisions

Credit Downgrades

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 severely limited. See Liquidity and Capital Resources—NPC and SPPC, for more information.

Power 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 3 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 3 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, 2003, for all suppliers continuing to provide power under a WSPP agreement was an approximate $70 million payment for NPC and an approximate $12 million payment for SPPC.

Power 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 15, Commitments and Contingencies of Notes to Financial Statements.

NPC and SPPC have established accrued liabilities, included in their Consolidated Balance Sheets as "Contract termination liabilities," of $280 million and $105 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, 2003, is approximately $245 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 contracts. Standard industry sponsored agreements include:

- the Gas Industry Standards Board (GISB) agreement which is used for physical gas transactions,
- the North American Energy Standards Board (NAESB) agreement which is used for physical gas transactions, and
- the Gas EDI Base Contract for Short-Term Sale and Purchase of Natural Gas which is also used for physical gas transactions.

Alternatively, some gas transactions are governed by a non-standard bilateral master agreement negotiated between the parties, or by the confirmation associated with the transaction. 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. NPC and SPPC gas hedging financial transactions are accomplished using long form confirms using gas call option buys and sells with three counterparties.

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.

Accounts Receivable Facility

On October 29, 2002, NPC and SPPC established accounts receivable purchase facilities of up to $125 million and $75 million, respectively. Actual amounts that may be advanced under the receivables purchase facilities will vary significantly depending upon, among other things, the time of year, the weather conditions and the delinquency rates of the Utilities' receivables. Based on 2003 accounts receivables and the variables discussed above NPC and SPPC had a maximum capacity of $82 million and $28 million and minimum capacity of $32 million and $13 million, respectively under the receivables facility. Both facilities were renewed on October 28, 2003, and will expire on October 26, 2004. If NPC and/or SPPC elect to activate their receivables purchase facilities, they will sell all of their accounts receivable generated from the sale

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

of electricity and natural gas to customers to their newly created bankruptcy-remote special purpose subsidiaries. The receivables sales will be without recourse except for breaches of customary representations and warranties made at the time of sale. The subsidiaries will, in turn, sell these receivables to a bankruptcy-remote subsidiary of SPR. SPR's subsidiary will issue variable rate revolving notes backed by the purchased receivables.

The agreements relating to the receivables purchase facilities contain various conditions to purchase covenants, and trigger events, and other provisions customary in receivables transactions. In addition to customary termination and mandatory repurchase events, each Utilities' receivables purchase facility may terminate in the event that the Utility or SPR defaults: (1) on the payment of indebtedness, or (2) on the payment of amounts due under a swap agreement, and such defaults aggregate to greater than $10 million and $5 million for the Utility and SPR, respectively.

Under the terms of the agreements relating to the receivables purchase facility, each Utility's facility may not be activated or, if activated, will be terminated in the event of a material adverse change in the condition, operations or business prospects of the Utility. SPR has agreed to guaranty the performance by NPC and SPPC of certain obligations as sellers and servicers under the receivables purchase facilities. NPC and SPPC intend to use their accounts receivables purchase facilities as back-up liquidity facilities and do not plan to activate these facilities in the foreseeable future.

Cross-Default Provisions

Certain financing agreements of SPR and the Utilities contain cross-default provisions that would result in an event of default under such financing agreements if there is a failure under other financing agreements of SPR and the Utilities 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 indenture pursuant to which SPR issued its 7.25% Convertible Notes due 2010 provides for an event of default if SPR or any of its significant subsidiaries (NPC and SPPC) fails to pay indebtedness in excess of $10 million or has any indebtedness of $10 million or more accelerated and declared due and payable;
- NPC's General and Refunding Mortgage Indenture, under which NPC has $1.3 billion of securities outstanding as of December 31, 2003, 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, 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 Bond to require NPC to redeem their series of Notes or the Bond 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 the Bond;
- NPC's receivables purchase facility may terminate in the event that either NPC or SPR defaults (i) in the payment of indebtedness, or (ii) in the payment of amounts due under hedge agreements, and such defaults aggregate to greater than $10 million and $5 million for NPC and SPR, respectively;
- NPC's Senior Unsecured Note Indenture, pursuant to which NPC issued its $130 million 6.20% Senior Unsecured Notes, Series B, due April 15, 2004, provides for a default if: (1) NPC fails to pay indebtedness (after any applicable grace period), or any of NPC's indebtedness is accelerated, and (2) such indebtedness aggregates $15 million, and (3) such indebtedness is not repaid and such acceleration is not rescinded within 30 days;
- SPPC's General and Refunding Mortgage Indenture, under which SPPC has $627 million of securities outstanding as of December 31, 2003, provides for an event of default if a matured event of default under SPPC's First Mortgage Indenture occurs;
- SPPC's Term Loan Agreement, Series E Bond, Series F Notes, and Series G Note provide for an event of default if (a) SPPC or any of its subsidiaries default (i) in the payment of indebtedness, or (ii) in the payment of amounts due under hedge agreements, and such defaults aggregate to greater than $10 million, or (b) SPPC's General and Refunding Mortgage Indenture ceases to be enforceable; and
- SPPC's receivables purchase facility may terminate in the event that either SPPC or SPR defaults (i) in the payment of indebtedness, or (ii) in the payment of amounts due under hedge agreements, and such defaults aggregate to greater than $10 million and $5 million for SPPC and SPR, respectively.

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.

NPC's $250 million Series E and $350 million Series G General and Refunding Mortgage Notes, $235 million Series H General and Refunding Mortgage Bond, and NPC's $130 million 6.2% Senior Unsecured Notes, Series B, due April 15, 2004, 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 Notes, Series G Notes, and Series H Bond were issued under NPC's General and Refunding Mortgage Indenture and NPC's Senior Unsecured Notes are secured by a General and Refunding Mortgage Bond, a default under any of the Series E Notes, the Series G Notes, the Series H Bond, and the Senior Unsecured Notes, 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 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 $100 million Term Loan Agreement, $103 million Series E Bond, $25 million Series F Notes, and $22 million Series G Note provide for an event of default if a judgment of $10 million or more is entered against SPPC and such judgment is not vacated, discharged, stayed or bonded pending appeal within 30 days. The Term Loan Agreement, the Notes and the Bond also prohibit the creation or existence of any liens on SPPC's properties except for liens specifically permitted under the Term Loan Agreement and the terms of Notes and the Bond. If a judgment lien is filed against SPPC, the filing of the lien will trigger an event of default. Upon an event of default under the Term Loan Agreement, the Administrative Agent under the Term Loan Agreement may, upon request of more than 50% of the lenders under the Term Loan Agreement, declare all amounts due under the Term Loan Agreement immediately due and payable. Currently, SPPC has $99 million outstanding under its Term Loan facility.

SPPC's obligations under the Term Loan Agreement are secured by a General and Refunding Mortgage Bond. If SPPC fails to repay all amounts due upon an acceleration under the Term Loan Agreement within 3 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.

Since the Series E Bond, Series F Notes, and the Series G Note were issued under SPPC's General and Refunding Mortgage Indenture, a default under any of these Notes or the Bond will trigger a default under SPPC's General and Refunding Mortgage Indenture. In the event that SPPC's Term Loan is accelerated and results in the acceleration of all amounts outstanding under SPPC's General and Refunding Mortgage Indenture or 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 2004 by approximately $5.3 million over the 2003 cost of $35.5 million. As of September 30, 2003, the measurement date, the plan had assets with a fair value that was less than the present value of the accumulated benefit obligation under the plan. During 2003, SPR and the Utilities contributed a total of $72.2 million to meet their funding obligations under the plan. At the present time it is not expected that any near term funding obligations will have a material adverse effect on liquidity.

Financing Transactions (SPR—Holding Company)

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.

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

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.

On February 14, 2003, SPR issued and sold $300 million of its 7.25% Convertible Notes due 2010. 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 our Common Stock plus an amount of cash equal to the then market value of 142.4564 shares of our Common Stock, subject to adjustment upon the occurrence of certain dilution events; or

(2) 219.1637 shares of our Common Stock, subject to adjustment upon the occurrence of certain dilution events.

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.

Effect of Holding Company Structure

Currently, SPR (on a stand-alone basis) has a substantial amount of outstanding debt and other obligations including, but not limited to: $300 million of its unsecured 8¾% Senior Notes due 2005; $240 million of its unsecured 7.93% Senior Notes due 2007; and $300 million of its 7.25% Convertible Notes due 2010.

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.

As of December 31, 2003, NPC, SPPC, and their subsidiaries had approximately $3.0 billion of debt and other obligations outstanding. Additionally, SPPC had $50.0 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.

Construction Expenditures and Financing (SPR Consolidated)

The table below provides SPR's consolidated cash construction expenditures and internally generated cash, net for 2001 through 2003 (dollars in thousands):

	2003	2002	2001
Cash construction expenditures	**$328,140**	$343,474	$ 302,025
Net cash flow from operating activities	**$268,744**	$472,505	$(1,053,844)
Less common & preferred cash dividends	**3,524**	24,485	64,917
Internally generated cash	**$265,220**	$448,020	$(1,118,761)
Internally generated cash as a percentage of cash construction expenditures	**81%**	130%	N/A

SPR's consolidated cash construction expenditures for 2004 through 2008 are estimated to be $2.4 billion. Construction expenditures for 2004 are projected to be $487.4 million and are expected to be financed by internally generated funds, including the recovery of deferred energy at the Utilities. It is anticipated that no capital contributions from SPR will be used to fund construction expenditures at the Utilities.

Cash provided by internally generated funds during 2004 assumes, among other things, that the Utilities will be able to refinance their debt maturing in 2004, that the Utilities will not be required to make any significant unanticipated cash outlays including additional payments of collateral into the escrow account established in connection with the Enron judgment, that there will be no material disallowances on the Utilities' deferred energy and general rate cases, that the Utilities will not have to pay higher than expected prices for fuel and purchased power and that the Utilities' current payment terms with their suppliers will remain unchanged. See Regulation and Rate Proceedings, Nevada Matters for additional information regarding the Utilities' recently filed rate cases and prior rate cases and Liquidity and Capital Resources for additional information regarding SPR's liquidity condition and cash flows.

In the event that SPR's and/or the Utilities' financial conditions worsen, they may be unable to finance their construction expenditures with internally generated funds and instead may need to raise all or a portion of the necessary funds through the capital markets or from activating the Utilities' accounts receivable purchase facilities to provide additional liquidity. For additional information regarding the accounts receivable purchase facilities, see Liquidity and Capital Resources. Each of the Utilities may activate its receivables purchase facility within five days upon the delivery of certain customary funding documentation and the delivery of General and Refunding Mortgage Bonds to secure the facility. If a material adverse event were to occur for either of the Utilities, it could potentially trigger a termination event with respect to the receivables facility and would also make it more difficult for the Utilities or SPR to access the capital markets for any such financing needs.

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 13, Retirement Plan and Postretirement Benefits of the Notes to Financial Statements, as of December 31, 2003, 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

	2004	2005	2006	2007	2008	Thereafter(1)	Total
NPC/SPPC Other Long-Term Debt	$218,970	$106,491	$ 58,909	$ 8,349	$329,466	$2,323,874	$3,046,059
SPR Long-Term Debt	19,666	300,000	—	240,218	—	300,000	859,884
Long-Term Debt Interest Payments	67,049	53,924	40,799	40,799	40,799	233,765	477,135
Purchased Power	415,783	330,607	270,817	241,564	224,633	2,903,001	4,386,405
Coal and Natural Gas	260,983	117,023	115,249	95,558	70,420	501,426	1,160,659
Operating Leases	10,211	9,054	8,133	6,000	5,974	22,603	61,975
Total Contractual Cash Obligations	$992,662	$917,099	$493,907	$632,488	$671,292	$6,284,669	$9,992,117

(1) SPR Long-Term Debt thereafter amount of $300 million represents the total amount of the 7.25% Convertible Notes due at maturity. This differs from the carrying value of $234,118 million included in the balance sheet amount of Long-Term Debt.

Capital Structure (SPR Consolidated)

SPR's actual capital structure on a consolidated basis at December 31, 2003, and 2002 was as follows (dollars in thousands):

	2003		2002	
Short-Term Debt(1)	**$ 263,636**	**5%**	$ 672,895	13%
Long-Term Debt	**3,579,674**	**67%**	3,257,596	61%
Preferred Stock	**50,000**	**1%**	50,000	1%
Common Equity	**1,435,394**	**27%**	1,327,166	25%
TOTAL	**$5,328,704**	**100%**	$5,307,657	100%

(1) Includes current maturities of long-term debt.

NEVADA POWER COMPANY

RESULTS OF OPERATIONS

NPC recognized net income of $19.3 million in 2003 compared to a net loss of $235 million in 2002 and net income $63.4 million in 2001. 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 $27.8 million of interest costs as a result of the September 26, 2003 judgment entered by the Enron Bankruptcy Court Judge, as described in Note 2, Liquidity Matters and Management's Plans of Notes to Financial Statements.

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.

NPC did not pay or declare a common stock dividend to its parent SPR in 2003. In the first quarter of 2002, NPC paid $10 million in dividends on its common stock to its parent, SPR, all of which was reinvested in NPC as a contribution to capital. No other dividend payments or capital contributions occurred in 2002.

Management has identified a number of risks and uncertainties that may have a negative impact on NPC's financial condition and results of operations. These risks and uncertainties are discussed in NPC's Liquidity and Financial Condition discussion below. If certain of these risks and uncertainties are decided adversely to NPC, NPC would likely experience charges that would offset in whole or in part NPC's earnings and gains and could result in significant losses to NPC.

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

	2003		2002		2001
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
ELECTRIC OPERATING REVENUES					
Residential	**$ 684,331**	**1.3%**	$ 675,837	4.8%	$ 644,875
Commercial	**346,223**	**0.3%**	345,342	14.1%	302,682
Industrial	**513,521**	**-1.3%**	520,116	16.2%	447,766
Retail revenues	**1,544,075**	**0.2%**	1,541,295	10.5%	1,395,323
Other(1)	**212,071**	**-41.0%**	359,739	-77.9%	1,629,780
TOTAL REVENUES	**$1,756,146**	**-7.6%**	$1,901,034	-37.2%	$3,025,103
Retail sales in thousands of megawatt-hours (MWh)	**17,959**	**4.4%**	17,197	2.4%	16,799
Average retail revenue per MWh	**$ 85.98**	**-4.1%**	$ 89.63	7.9%	$ 83.06

(1) Primarily wholesale, as discussed below.

NPC's retail revenues were slightly higher in 2003 compared to 2002 primarily due to 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% rate decrease that was effective May 19, 2003, which was the result of NPC's Deferred Energy Case (refer to Regulation and Rate Proceedings, later). Also 2003 revenues 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.

NPC's retail revenues increased in 2002 compared to 2001 primarily due to a combination of customer growth and a net rate increase resulting from NPC's General Rate and Deferred Energy Cases (refer to Regulation and Rates Proceedings, later). The number of residential, commercial, and industrial customers increased over the prior year by 4.9%, 5.7%, and 2.1%, respectively. Effective April 1, 2002, the PUCN authorized an increase in energy related rates that are used to recover current and previously incurred fuel and purchased power costs. In addition to that rate increase, the PUCN also granted NPC the authority to increase its energy recovery rate by $.01 per kilowatt-hour for the month of June 2002 only. This one-time increase in rates generated approximately $16 million, which accelerated the recovery of previously incurred fuel and purchased power costs.

The decrease in Electric Operating Revenues—Other for each year was primarily due to a decrease in the sales volumes of wholesale electric power to other utilities, and a reduction in hedging activity, as described under purchased power below.

Purchased Power

	2003		2002		2001
(dollars in thousands, except for amounts per unit)	**Amount**	**Change from Prior Year**	Amount	Change from Prior Year	Amount
PURCHASED POWER	**$744,271**	**-40.1%**	$1,241,783	-59.0%	$3,026,336
Purchased power in thousands of MWh	**11,637**	**-9.8%**	12,908	-33.0%	19,268
Average cost per MWh of Purchased Power(1)	**$ 62.57**	**-20.3%**	$ 78.46	-50.0%	$ 157.07

(1) Not including contract termination costs, of $16.1 million and $228.5 million for the year ending 2003 and 2002, respectively.

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 20.3% primarily due to lower Short-Term Firm energy prices. These price decreases were the result of a less volatile energy market. A $228 million charge for terminated contracts recorded in 2002 further contributed to the overall decrease in the total cost of purchased power. See Liquidity and Capital Resources, later, for a discussion of these terminated power contracts. Volumes purchased decreased by 9.8% 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%. Risk management activities include transactions entered into for hedging purposes and to optimize purchased power costs. See Energy Supply, later, for a discussion of the Utilities' purchased power procurement strategies.

Purchased power costs were lower in 2002 as compared to 2001 due to a 33% decrease in the volume purchased and a decrease in the per unit cost of power of 50%. Purchased power costs were lower primarily due to lower Short-Term Firm energy prices and volumes. Purchases associated with risk management activities, which are included in Short-Term Firm energy, decreased significantly in both volume and price in 2002.

Fuel for Power Generation

	2003		2002		2001
(dollars in thousands, except for amounts per unit)	**Amount**	**Change from Prior Year**	Amount	Change from Prior Year	Amount
FUEL FOR POWER GENERATION	**$319,711**	**3.4%**	$309,293	-30.0%	$441,900
Thousands of MWhs generated	**10,026**	**-1.2%**	10,147	2.5%	9,899
Average fuel cost per MWh of Generated Power	**$ 31.89**	**4.6%**	$ 30.48	-31.7%	$ 44.64

NPC's 2003 fuel expense increased 3.4% compared to 2002 primarily due to an increase in fuel costs, mainly in gas prices. This increase was slightly offset by a decrease in overall MWhs generated. In 2002, NPC's fuel expense decreased 30% compared to 2001 primarily due to a substantial decrease in natural gas prices. This was slightly offset by an increase in coal prices and an overall increase in MWhs generated.

Deferral of Energy Costs—Net

	2003		2002		2001
(dollars in thousands)	**Amount**	**Change from Prior Year**	Amount	Change from Prior Year	Amount
Deferral energy costs—electric—net	**$ 95,911**	**N/A**	$(179,182)	-80.9%	$(937,322)
Deferred energy costs disallowed	**45,964**	**N/A**	434,123	N/A	—
	$141,875	**N/A**	$ 254,941	N/A	$(937,322)

The increase in Deferral of energy costs—electric—net for the twelve months ended December 31, 2003 compared to the same period in 2002, resulted primarily from the deferral in the second and fourth quarter of 2002 of approximately $228 million for contract termination costs. Additionally, 2003 costs increased as a result of greater amortization of prior deferred energy costs compared to 2002. The 2003 increase in deferred energy costs was partially offset by an increase over 2002 in the amount that fuel and purchase power costs exceeded the recovery of those costs through rates. During periods when actual fuel and purchase power costs exceed amounts recovered through rates, the excess is shown as a reduction in costs. The increase in deferral energy costs—electric—net for the twelve months ended December 31, 2002, compared to the same period in the prior year, reflects the amortization in 2002 of prior deferred costs pursuant to the PUCN's decision on NPC's deferred energy rate case, which resulted in increased rates beginning April 1, 2002, and the one time rate increase of $0.01 per kilowatt-hour for the month of June 2002. The amortization was offset, in part, by the recording of current year deferrals of electric energy costs. Deferral of energy costs—electric—net also reflects the $228 million for contract termination charges discussed above.

Deferred energy costs disallowed for the year ended 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 their May 12, 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.

See Critical Accounting Policies, earlier, and Note 1 of Notes to Financial Statements, Summary of Significant Accounting Policies for more information regarding deferred energy accounting.

Allowance For Funds Used During Construction (AFUDC)

	2003		2002		2001
(dollars in thousands)	**Amount**	**Change from Prior Year**	Amount	Change from Prior Year	Amount
Allowance for other funds used during construction	**$2,845**	**N/A**	$ (153)	-59.9%	$ (382)
Allowance for borrowed funds used during construction	**2,700**	**-20.9%**	3,412	59.4%	2,141
	$5,545	**70.1%**	$3,259	85.3%	$1,759

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 Construction Work in Progress (CWIP) balance on which AFUDC is calculated. AFUDC for NPC is higher in 2002 compared to 2001 due to increases in CWIP and adjustments in 2001 to amounts assigned to specific components of facilities that were completed in different periods.

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

Other (Income) and Expenses

(dollars in thousands)	2003 Amount	2003 Change from Prior Year	2002 Amount	2002 Change from Prior Year	2001 Amount
Other operating expense	**$ 195,483**	**16.5%**	$ 167,768	-1.0%	$ 169,442
Maintenance expense	**$ 48,226**	**17.1%**	$ 41,200	-8.7%	$ 45,136
Depreciation and amortization	**$ 109,655**	**11.7%**	$ 98,198	5.5%	$ 93,101
Income taxes	**$ (12,734)**	**-90.5%**	$(133,411)	N/A	$ 17,775
Interest charges on long-term debt	**$ 142,143**	**24.1%**	$ 114,527	17.8%	$ 97,240
Interest charges—other	**$ 51,029**	**138.5%**	$ 21,395	61.9%	$ 13,219
Interest accrued on deferred energy	**$ (22,891)**	**84.4%**	$ (12,414)	-71.0%	$ (42,743)
Other income	**$ (18,344)**	**N/A**	$ (742)	-84.1%	$ (4,669)
Other expense	**$ 5,944**	**-40.2%**	$ 9,933	110.9%	$ 4,709
Income taxes—other income and expense	**$ 12,120**	**N/A%**	$ 1,627	-89.1%	$ 14,962

The increase in Other operating expense during 2003 compared to 2002 resulted primarily from the increase in 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. Additional factors contributing to higher costs in 2003 include 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.

The decrease in Other operating expense for 2002 compared to 2001 reflects the absence in 2002 of $10.0 million of provisions which were established in 2001 for retail uncollectible accounts as well as $12.6 million for uncollectible amounts associated with the California Power Exchange, which NPC continues to pursue for collection. Additional factors that resulted in lower other operating expenses during 2002 include the reversal of a $6 million provision originally established in 2001 pursuant to the PUCN order for costs associated with the conclusion of electric industry restructuring. NPC had no 2002 short-term incentive plan expense compared to $5.5 million in 2001. These increases were substantially offset by increases in Other operating expense during 2002 include $14.7 million in legal and advisory fees associated with liquidity issues and the consequences of the PUCN's deferred energy rate case decision. Additional increases in Other operating expense in 2002 included $12.1 million related to collection for and write-off of uncollectible accounts.

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 2003 costs was a result of maintenance performed at the Clark, Mohave, and Navajo generating facilities.

Maintenance expense during 2002 decreased compared to the prior year as a result of delaying maintenance at Reid Gardner. This decrease was partially offset by higher miscellaneous maintenance costs at the Mohave and Navajo generating facilities.

An increase in depreciation and amortization expense between 2003 and 2002 was the result of increases to plant-in-service. An increase in the computer depreciation rate pursuant to a PUCN order and additions to plant-in-service were the primary cause of NPC's increase in depreciation and amortization expense in 2002 compared to 2001.

As a result of pretax operating losses, which include interest charges for 2003 and 2002, NPC incurred income tax benefits. During 2003, NPC's income tax benefit decreased due to smaller pretax operating losses in 2003 compared to pretax operating losses in 2002. The decrease in pretax operating losses resulted largely from the write-off in 2002 of disallowed deferred energy costs partially offset in 2003 by a decrease in revenues and increases in other operating, maintenance, depreciation, and interest expenses. See Note 12 of Notes to Financial Statements, Taxes, for additional information regarding the computation of income taxes.

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 in October 2002 of $250 million additional debt at an interest rate of 10.875% and the issuance, in August 2003 of $350 million General and Refunding Bonds at an interest rate of 9.00%. The redemptions, in September 2003 and October 2002, of $350 million and $15 million, respectively, slightly offset the increase in interest during 2003 over 2002. NPC's interest charges increased in 2002 compared to 2001 due to additional issuances of long-term debt at higher interest rates during 2002 and to the payment of a full year of interest on $100 million of long-term debt outstanding throughout 2001. In 2002, NPC redeemed $15 million in debt and issued additional debt of $250 million. See Note 8 of Notes to Financial Statements, Long-Term Debt for additional information regarding long-term debt.

Interest charges—other for the year ended December 31, 2003, increased, compared to the same period in 2002, due to higher interest on terminated contracts. In September 2003, NPC recorded $27.8 million of additional interest costs on terminated contracts as a result of a final judgment issued September 26, 2003, by the Bankruptcy Court Judge overseeing the bankruptcy case of Enron Power Marketing (Enron). See Note 15, Commitments and Contingencies, of Notes to Financial Statements for more information regarding the Enron litigation. NPC's interest charges—other increased in 2002 compared to 2001 due primarily to interest on extended payments to fuel and power suppliers resulting from renegotiated purchased power and fuel contracts, (terminated/delayed contracts). Increased credit facility fees also contributed to the increase in 2002 over the prior year (refer to Liquidity and Capital Resources for further discussion of power and fuel contracts and the credit facilities).

Interest accrued on deferred energy costs for the year ended December 31, 2003 compared favorably to the same period in 2002 due to the first quarter 2002 write-off of approximately $20.1 million of carrying charges, net of taxes, on deferred energy costs that were disallowed by the PUCN in its March, 29, 2002, decision on NPC's deferred energy rate case. The 2002 write-off was partially offset by the recording of carrying charges on deferred energy costs incurred. Interest accrued on deferred energy decreased during 2002, compared to 2001 due to a significant decline in the related deferred fuel and purchased power balances resulting from the write-off referred to above. (Refer to Regulation and Rate Proceedings for further discussion of deferred energy accounting issues).

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. Other income for the year ended December 31, 2002 decreased from 2001 due, primarily, to an expense adjustment related to the sale of SO2 emission allowances ordered by the PUCN.

NPC's Other expense decreased for the year ended December 31, 2003 compared to the same period in 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. Other expense increased in 2002 compared to 2001 due primarily to the same costs (ballot initiative and advertising), along with increased costs for assistance programs, corporate advertising, and miscellaneous customer information activities.

Income Taxes—Other Income and Expense increased in 2003 compared to 2002 due to an increase in pretax 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's cash flows were less during 2003 compared to 2002 resulting from a decrease in cash flows from financing activities that was partially offset by smaller increases in cash flows from operating and investing activities. Cash flows from financing activities were lower in 2003 because of cash that was provided during 2002 from the net issuance of long-term debt. 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 offsetting the improved cash flows from operations during 2003 was the requirement for NPC to prepay or accelerate the payment for fuel and power purchases during 2003 and the receipt of an income tax refund in 2002. Cash flows from investing activities were improved during 2003 because of a reduction in cash utilized for construction activities.

NPC's net cash flows improved in 2002 compared to 2001. This resulted from an increase in cash flows from operating activities offset in part by decreases in cash flows from investing and financing activities. Although NPC recorded a substantial loss for 2002, compared to net income in 2001, the 2002 loss resulted largely from the write-off of disallowed deferred energy costs for which the cash outflow had occurred in 2001. Other factors contributing to 2002's improved cash flows from operating activities include the collection of deferred energy costs from customers and lower energy prices. Cash flows from operating activities in the current year also reflect the receipt of an income tax refund. Cash flows from investing activities decreased because of additional cash utilized for construction activities during 2002 compared to 2001. Cash flows from financing activities were lower because of less net long-term debt issued, decreases in short-term borrowings and less cash invested by NPC's parent, SPR, during 2002.

LIQUIDITY AND CAPITAL RESOURCES

NPC had cash and cash equivalents of approximately $144.9 million at December 31, 2003 and $141.2 million at January 31, 2004.

As discussed in Construction Expenditures and Financing and Contractual Obligations below, NPC anticipates capital requirements for construction costs in 2004 will be approximately $381 million which NPC expects to finance with internally generated funds, including the recovery of deferred energy. NPC has $130 million of long-term debt maturing on April 15, 2004. NPC currently expects to refinance all of this debt prior to maturity through the issuance and sale of its General and Refunding Mortgage Securities.

Due to NPC's weakened financial condition, NPC has been required to either pre-pay its power purchases or make more frequent payments on its power deliveries. As a result of unseasonably cool weather during the spring of 2003 and its prepayment and more frequent payment obligations for its summer 2003 power requirements, NPC's liquidity was significantly constrained during the early summer months of 2003. Consequently, on June 30, 2003, NPC entered into a $60 million revolving Credit Agreement to provide additional liquidity to NPC for its summer 2003 power purchases.

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

NPC anticipates that based upon its current cash balances and expected cash flows leading up to the summer 2004 season, NPC will need additional liquidity at the onset of the summer 2004 season to support its power purchases. Currently, management believes that NPC will be able to enter into financings and/or credit facilities to meet its summer 2004 cash needs. If NPC has to pay higher than expected prices for fuel and purchased power, if NPC's suppliers require changes to NPC's current payment terms, or if NPC does not have sufficient available liquidity to obtain fuel and purchased power, particularly at the onset of the 2004 summer season, NPC may be required to issue or incur additional indebtedness, enter into additional liquidity facilities or utilize its receivables purchase facility. If NPC is unable to enter into financings to provide it with sufficient additional liquidity and to repay its maturing indebtedness, whether due to unfavorable conditions in the capital markets, lack of regulatory authority to issue or incur such debt, credit downgrades by either S&P or Moody's resulting from the uncertainties discussed in this section, or restrictive covenants in certain of its financing agreements (see below), its ability to provide power and fund its expected construction costs and its financial condition and cash flows will be adversely affected.

Management has identified a number of other uncertainties that may have a negative impact on NPC's financial condition and cash flows. The most significant of these uncertainties are:

- whether there will be any further requirements to pay the judgment of the Bankruptcy Court overseeing Enron's bankruptcy proceeding in favor of Enron or to provide further cash collateral, to secure the stay of the judgment against NPC pending further appeal,
- whether NPC will be able to recover regulatory assets in its current and future rate cases, especially previously incurred deferred fuel and purchased power costs, and to provide sufficient revenues to support its operations, and
- whether NPC will be able to successfully refinance its maturing long-term debt and secure additional liquidity necessary to support its operations, including the purchase of fuel and power.

Because of the relationships among the uncertainties described above, an adverse development with respect to a combination of these uncertainties, could have a material adverse effect on NPC's financial condition, results of operations and liquidity, and could make it difficult for NPC to continue to operate outside of bankruptcy.

Effect of Rate Case Decisions

Credit Downgrades and Credit Facilities

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. As a result of these downgrades, NPC's ability to access the capital markets to raise funds were severely limited. Since SPR's credit ratings were similarly downgraded, SPR's ability to make capital contributions to NPC also became severely limited.

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.

Power 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 15, Commitments and Contingencies of Notes to Financial Statements.

Included in NPC's Consolidated Balance Sheets as "Contract termination liability," are $280 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, 2003, is approximately $245 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.

Credit Facility

On June 30, 2003, NPC entered into a $60 million revolving Credit Agreement to provide additional liquidity to NPC for its summer 2003 power purchases. This facility was paid off on August 11, 2003, and was terminated on August 18, 2003.

Accounts Receivable Facility

On October 29, 2002, NPC established an accounts receivable purchase facility for up to $125 million. Actual amounts that may be advanced under the receivables purchase facilities will vary significantly depending upon, among other things, the time of year, the weather conditions and the delinquency rates of NPC's receivables. Based on 2003 accounts receivables and the variables discussed above NPC had a maximum capacity of $82 million and minimum capacity of $32 million under the receivables facility. The receivables purchase facility was renewed on October 28, 2003, and expires as of October 26, 2004. If NPC elects to activate the receivables purchase facility, NPC will sell all of its accounts receivable generated from the sale of electricity to customers to its newly created bankruptcy-remote special purpose subsidiary. The receivables sales will be without recourse except for breaches of customary representations and warranties made at the time of sale. The subsidiary will, in turn, sell these receivables to a bankruptcy-remote subsidiary of

SPR. SPR's subsidiary will issue variable rate revolving notes backed by the purchased receivables.

The agreements relating to the receivables purchase facility contain various conditions to purchase, covenants and trigger events, and other provisions customary in receivables transactions. In addition to customary termination and mandatory repurchase events, the receivables purchase facility may terminate in the event that either NPC or SPR defaults: (1) on the payment of indebtedness, or (2) on the payment of amounts due under a swap agreement and such defaults aggregate to greater than $10 million and $5 million for NPC and SPR, respectively.

Under the terms of the agreements relating to the receivables purchase facility, NPC's facility may not be activated or, if activated, will be terminated in the event of a material adverse change in the condition, operations or business prospects of NPC. In addition, the agreements contain a limitation on the payment of dividends by NPC to SPR that is identical to the limitation contained in NPC's General and Refunding Mortgage Notes, Series E, described below. SPR has agreed to guaranty NPC's performance of certain obligations as a seller and servicer under the receivables purchase facility.

NPC has agreed to issue a $125 million General and Refunding Mortgage Bond upon activation of the receivables purchase facility. The full principal amount of the bond would secure certain of NPC's obligations as seller and servicer, plus certain interest, fees, and expenses thereon to the extent not paid when due, regardless of the actual amounts owing with respect to the secured obligations. As a result, in the event of an NPC bankruptcy or liquidation, the holder of the bond securing the receivables purchase facility may recover more on a pro rata basis than the holders of other General and Refunding Mortgage securities, who could recover less on a pro rata basis than they otherwise would recover. However, in no event will the holder of the bond recover more than the amount of obligations secured by the bond.

NPC intends to use the accounts receivable purchase facility as a back-up liquidity facility and does not plan to activate this facility in the foreseeable future. NPC may activate the facility within five days upon the delivery of certain customary funding documentation and the delivery of the $125 million General and Refunding Mortgage Bond. As of February 29, 2004, this facility had not been activated.

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, 2003, $372.5 million of NPC's first mortgage bonds were outstanding. In connection with the issuance of its Series E Notes and its Series G 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.

As amended, NPC does not anticipate that the First Mortgage Indenture dividend restriction 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, 2003, $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, as of December 31, 2003, NPC had the capacity to issue approximately $685.8 million of additional General and Refunding Mortgage securities, which amount does not include the retirement of approximately $24 million of NPC's $235 million Series H, General and Refunding Mortgage Bond (discussed below).

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 Notes, the Series G Notes, the Series H Bond, and the Receivables Purchase Facility Agreements limit the amount of additional indebtedness that NPC may issue and the reasons for which such indebtedness may be issued. In the event funding becomes necessary, NPC has reserved $125 million of General and Refunding Mortgage bonds for issuance upon the initial funding of NPC's receivables facility.

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.

PUCN Order

On December 17, 2003, the PUCN issued an order in connection with its authorization of the issuance of short-term debt securities by NPC and SPPC. The PUCN order, for Dockets 03-10022 and 03-10023, permits NPC and SPPC to dividend an aggregate of $70 million per year to SPR through December 31, 2005. The PUCN order also provides that the dividend limitation may be reviewed in

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

a subsequent application to grant short-term debt authority and that, in the event that exigent circumstances are experienced in the interim, either NPC or SPPC may petition the PUCN to review the dollar limitation.

Financing Transactions and Covenants

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.

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 were issued with registration rights. 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.

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. See Note 15, Commitments and Contingencies of Notes to Financial Statements for more information regarding the Enron litigation. The Series H Bond will be held in escrow until such time as the stay order is lifted, entry of an order affirming the judgment and a denial of stay of such order, or a settlement agreement is entered into between NPC and Enron. NPC expects to enter into a Remarketing Agreement with Enron and a Remarketing Agent which will provide for the possibility of the Series H Bond being remarketed in the event that the Series H Bond is released from escrow for the benefit of Enron. 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 G Notes.

The Series E Notes, the Series G Notes, and the Series H Bond limit the amount of payments in respect of common stock that NPC may pay to SPR. However, that 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 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 both series of Notes and the Bond also permit NPC to make payments to SPR in an aggregate amount not to exceed: (1) under the Series E Notes, $15 million from the date of the issuance of the Series E Notes, and (2) under the Series G Notes and the Series H Bond, $25 million from the date of the issuance of the Series G Notes and the Series H Bond, 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 Notes, the Series G Notes or the Series H Bond,
- 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, 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.

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

- 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
- the debt incurred is specifically permitted, 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 NPC's obligations with respect to energy suppliers, or
- in the case of the Series G Notes and the Series H Bond, indebtedness incurred to finance capital expenditures pursuant to NPC's 2003 IRP.

If NPC's Series E Notes, the Series G Notes, or the 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 remains investment grade.

Among other things, the Series E Notes, Series G Notes, and the 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.

Cross-Default Provisions

Certain financing agreements of NPC contain cross-default provisions that would result in an event of default under such financing agreements if there is a failure under other financing agreements of NPC and SPR 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 or SPR 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 as of December 31, 2003, 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, 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 securities to require NPC to redeem their securities 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 holders for such series of securities;
- NPC's receivables purchase facility may terminate in the event that either NPC or SPR defaults (i) in the payment of indebtedness, or (ii) in the payment of amounts due under hedge agreements, and such defaults aggregate to greater than $10 million and $5 million for NPC and SPR, respectively; and
- NPC's Senior Unsecured Note Indenture, pursuant to which NPC issued its $130 million 6.20% Senior Unsecured Notes, Series B, due April 15, 2004, provides for a default if: (1) NPC fails to pay indebtedness (after any applicable grace period), or any of NPC's indebtedness is accelerated, and (2) such indebtedness aggregates $15 million, and (3) such indebtedness is not repaid and such acceleration is not rescinded within 30 days.

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.

NPC's $250 million Series E and $350 million Series G General and Refunding Mortgage Notes, $235 million Series H General and Refunding Mortgage Bond and NPC's $130 million 6.2% Senior Unsecured Notes, Series B, due April 15, 2004, 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 Notes, Series G Notes, and the Series H Bond were issued under NPC's General and Refunding Mortgage Indenture and NPC's Senior Unsecured Notes are secured by a General and Refunding Mortgage Bond, a default under any of the Series E Notes, the Series G Notes, the Series H Bond, and the Senior Unsecured Notes, 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 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.

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

Limitations on Indebtedness

The terms of NPC's Series E Notes, which mature in 2009, NPC's Series G Notes, which mature in 2013, and NPC's Series H Bond 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, 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 and the Series H Bond, indebtedness to finance capital expenditures incurred pursuant to NPC's 2003 IRP.

At December 31, 2003, NPC met the fixed charge ratio test set forth in (1) above. If NPC's Series E Notes, Series G 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.

In addition, the PUCN conducted hearings on NPC's IRP on October 16, 2003. 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 construction of the combined cycle units, issues with transmission reservations, or difficulties financing the IRP. As such, NPC may need to expend up to approximately $500 million prior to the summer of 2007 for the construction and/or acquisition of generation facilities.

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 2004 by approximately $5.3 million over the 2003 cost of $35.5 million. As of September 30, 2003, the measurement date, the plan had assets with a fair value that was less than the present value of the accumulated benefit obligation under the plan. During 2003, NPC contributed a total of $58.7 million to meet its funding obligations under the plan. At the present time it is not expected that any near term funding obligations will have a material adverse effect on liquidity.

Construction Expenditures and Financing

The table below provides an overview of NPC's consolidated cash construction expenditures and internally generated cash, net for 2001 through 2003 (dollars in thousands):

	2003	2002	2001
Cash construction expenditures	**$204,611**	$250,441	$ 196,896
Net cash flow from operating activities	**$265,628**	$257,607	$(757,402)
Common and preferred cash dividends paid	**—**	10,000	33,014
Internally generated cash	**265,628**	247,607	(790,416)
Investment by parent company	**—**	10,000	474,921
Total cash available	**$265,628**	$257,607	$(315,495)
Internally generated cash as a percentage of cash construction expenditures	**130%**	99%	N/A
Total cash generated (used) as a percentage of cash construction expenditures	**130%**	103%	N/A

NPC's estimated cash construction expenditures for 2004 through 2008 are $1.97 billion. Construction expenditures for 2004 are projected to be $381 million and are expected to be financed by internally generated funds, including the recovery of deferred energy.

Cash provided by internally generated funds during 2004 assumes, among other things, that NPC will be able to refinance its debt maturing in 2004, that NPC will not be required to make any significant unanticipated cash outlays including additional payments of collateral into the escrow account established in connection with the Enron judgment, that there will be no material disallowances in NPC's 2003 deferred energy and general rate cases, that NPC will not have to pay higher than expected prices for fuel and purchased power and that NPC's current payment terms with its suppliers will remain unchanged. See Regulation Proceedings, Nevada Matters for additional information regarding the NPC recently filed deferred energy rate case and prior deferred energy rate cases and Liquidity and Capital Resources for additional information regarding NPC's liquidity condition and cash flows.

In the event that NPC is unable to finance its construction expenditures with internally generated funds NPC may need to raise all or a portion of the necessary funds through the capital markets or from activating its accounts receivables purchase facility to provide additional liquidity. For additional information regarding the accounts receivables purchase facility, see Liquidity and Capital Resources. NPC may activate its receivables purchase facility within five days upon the delivery of certain customary funding documentation and the delivery of $125 million of its General and Refunding Mortgage Bonds to secure the facility. If a material adverse event were to occur, it could potentially trigger a termination event with respect to the receivables facility and would also make it more difficult for NPC to access the capital markets for any such financing needs.

Contractual Obligations

The table below provides NPC's consolidated contractual obligations, not including estimated construction expenditures described above, as of December 31, 2003, 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

	2004	2005	2006	2007	2008	Thereafter	Total
Long-Term Debt	$135,570	$ 6,091	$ 6,509	$ 5,949	$ 7,066	$1,886,023	$2,047,208
Long-Term Debt Interest	145,984	141,617	141,617	141,615	141,614	1,373,886	2,086,333
Purchased Power	358,753	301,222	240,848	210,797	192,374	2,897,461	4,201,455
Coal and Natural Gas	97,439	41,436	44,058	42,736	24,736	245,764	496,169
Operating Leases	1,882	1,501	936	35	8	450	4,812
Total Contractual Cash Obligations	$739,628	$491,867	$433,968	$401,132	$365,798	$6,403,584	$8,835,977

Capital Structure

As of December 31, 2003, NPC had no short-term debt outstanding and current maturities of long-term debt of $130 million due April 15, 2004.

For a complete discussion of the NPC financing transactions please see the both the Accounts Receivable Facility and the Financing Transactions sections of the Liquidity and Capital Resources—NPC discussion.

NPC's actual consolidated capital structure at December 31, 2003, and 2002 was as follows (dollars in thousands):

	2003		2002	
Short-Term Debt[1]	**$ 135,570**	**4%**	$ 354,677	11%
Long-Term Debt	**1,899,709**	**59%**	1,683,310	53%
Common Equity	**1,174,645**	**37%**	1,149,131	36%
TOTAL	**$3,209,924**	**100%**	$3,187,118	100%

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

SIERRA PACIFIC POWER COMPANY

RESULTS OF OPERATIONS

SPPC recognized a net loss of $23.3 million in 2003, compared to a net loss of $14.0 million in 2002 and net income of $49.6 million in 2001. 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 $12.4 million of interest costs as a result of the September 26, 2003, Judgment by the Enron Bankruptcy Court Judge as described in Note 2, Liquidity Matters and Management's Plans of Notes to Financial Statements. 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.

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. During 2002, SPPC paid $44.9 million in common stock dividends to its parent, SPR, $10 million of which was reinvested in SPPC as a contribution to capital.

Management has identified a number of risks and uncertainties that may have a negative impact on SPPC's financial condition and results of operations. These risks and uncertainties are discussed in SPPC's Liquidity and Capital Resources discussion below. If certain of these risks and uncertainties are decided adversely to SPPC, SPPC would likely experience one-time charges that would offset in whole or in part SPPC's earnings and gains and could result in significant losses to SPPC.

SPPC closed the sale of its water utility business in June 2001. Accordingly, the water business is reported as a discontinued operation and the continuing operating results have been reclassified to report separately the net results of operations from the water business.

The components of gross margin are (dollars in thousands):

	2003	2002	2001
Operating Revenues:			
Electric	**$ 868,280**	$ 931,251	$1,401,778
Gas	**161,586**	149,783	145,652
Total revenues	**$1,029,866**	$1,081,034	$1,547,430
Energy Costs:			
Purchased Power	**$ 360,073**	$ 545,040	$1,025,741
Fuel for Power generation	**201,701**	144,143	286,719
Deferred energy costs disallowed[1]	**45,000**	56,958	—
Deferral of energy costs—electric—net	**1,982**	(54,632)	(198,826)
Gas purchased for resale	**111,675**	91,961	136,534
Deferral of energy costs—gas—net	**16,155**	24,785	(23,170)
Total energy costs	**$ 736,586**	$ 808,255	$1,226,998
Energy Costs by Segment:			
Electric	**$ 608,756**	$ 687,652	$1,113,634
Gas	**127,830**	120,603	113,364
Total energy costs	**736,586**	808,255	1,226,998
Gross margin	**$ 293,280**	$ 272,779	$ 320,432
Gross Margin by Segment:			
Electric	**$ 259,524**	$ 243,599	$ 288,144
Gas	**33,756**	29,180	32,288
Total	**$ 293,280**	$ 272,779	$ 320,432

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

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

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 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

	2003		2002		2001
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
ELECTRIC OPERATING REVENUES					
Residential	**$230,299**	**5.3%**	$218,663	4.0%	$ 210,350
Commercial	**276,453**	**2.9%**	268,631	10.1%	243,883
Industrial	**280,047**	**3.9%**	269,610	6.2%	253,936
Retail revenues	**786,799**	**3.9%**	756,904	6.9%	708,169
Other(1)	**81,481**	**-53.3%**	174,347	-74.9%	693,609
TOTAL REVENUES	**$868,280**	**-6.8%**	$931,251	-33.6%	$1,401,778
Retail sales in thousands of megawatt-hours (MWh)	**8,901**	**2.4%**	8,692	-0.4%	8,729
Average retail revenue per MWh	**$ 88.39**	**1.5%**	$ 87.08	7.3%	$ 81.13

(1) Primarily wholesale, as discussed below.

SPPC's retail revenues increased in 2003 as compared to 2002 due to a combination of factors. Increased sales resulting from hotter than normal summer temperatures, which resulted in higher revenues from air conditioning were partially offset by lower winter sales from heating as a result of warmer than normal winter weather. 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, (see below) 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 (see Regulation and Rate Proceedings, later).

SPPC's retail revenues were higher in 2002 than 2001 primarily as a result of a net rate increase resulting from SPPC's General Rate and Deferred Energy cases. Effective June 1, 2002, the PUCN authorized an increase in SPPC's energy related rates that were used to recover current and previously incurred fuel and purchased power costs.

The decrease in Electric Operating Revenues—Other during 2003 and 2002 compared to the preceding years was primarily due to a decrease in the sales volumes of wholesale electric power to other utilities and a reduction in sales associated with risk management activities.

Gas Operating Revenues

	2003		2002		2001
(dollars in thousands, except for amounts per unit)	**Amount**	**Change from Prior Year**	Amount	Change from Prior Year	Amount
GAS OPERATING REVENUES					
Residential	**$ 75,571**	**-1.1%**	$ 76,400	19.7%	$ 63,815
Commercial	**36,531**	**-1.3%**	37,018	20.7%	30,680
Industrial	**13,930**	**-31.2%**	20,252	12.9%	17,941
Retail revenues	**126,032**	**-5.7%**	133,670	18.9%	112,436
Wholesale	**32,978**	**133.5%**	14,121	-57.6%	33,298
Miscellaneous	**2,576**	**29.3%**	1,992	N/A	(82)
TOTAL REVENUES	**$161,586**	**7.9%**	$149,783	2.8%	$145,652
Retail sales in thousands of decatherms	**13,089**	**-6.7%**	14,030	-1.7%	14,276
Average retail revenues per decatherm	**$ 9.63**	**1.0%**	$ 9.53	20.9%	$ 7.88

SPPC's retail gas revenues were lower in 2003 primarily due to warmer than normal winter weather and a decrease in energy related rates that became effective December 26, 2002. This decrease in the retail rates was the result of SPPC's Purchased Gas Adjustment filing (see Regulation and Rate 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. 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).

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 in 2003 compared to 2002 primarily due to an increase in revenues pertaining to the transportation of gas for industrial customers that shifted to SPPC's transportation tariff.

2002 retail gas revenues were significantly higher than the prior year primarily due to a rate increase resulting from SPPC's 2001 Purchased Gas Adjustment filing. Effective November 5, 2001, the PUCN authorized this increase in energy related rates that are used to recover current and previously incurred purchased gas. Wholesale gas revenues were significantly lower during 2002 compared to 2001, due to fewer wholesales and lower prices.

Purchased Power

	2003		2002		2001
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
PURCHASED POWER	**$360,073**	**-33.9%**	$545,040	-46.9%	$1,025,741
Purchased power in thousands of MWh	**6,575**	**-8.8%**	7,206	-5.1%	7,591
Average cost per MWh of Purchased power(1)	**$ 54.44**	**-14.4%**	$ 63.59	-52.9%	$ 135.13

(1) Not including contract termination costs of $2.1 million and $86.8 million for the years ending 2003 and 2002, respectively.

Purchased power costs decreased in 2003 due to overall price and volume decreases, 14.4% and 8.8% respectively. 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 48% 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.

Purchased power costs were lower in 2002 than 2001 as a result of lower prices (due to a more stable energy market) and a 40% decrease in wholesale sales activity.

Fuel For Power Generation

	2003		2002		2001
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
FUEL FOR POWER GENERATION	**$201,701**	**39.9%**	$144,143	-49.7%	$286,719
Thousands of MWh generated	**4,226**	**-10.1%**	4,699	-21.5%	5,986
Average fuel cost per MWh of Generated Power	**$ 47.73**	**55.6%**	$ 30.67	-36.0%	$ 47.90

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

Fuel for power generation costs in 2002 were lower than 2001 due to lower gas prices and to a lesser extent to lower system load requirements.

Gas Purchased for Resale

	2003		2002		2001
	Amount	**Change from Prior Year**	Amount	Change from Prior Year	Amount
GAS PURCHASED FOR RESALE	**$111,675**	**21.4%**	$91,961	-32.6%	$136,534
Gas Purchased for Resale (in thousands of decatherms)	**20,026**	**11.7%**	17,930	7.0%	16,756
Average cost per decatherm	**$ 5.58**	**8.8%**	$ 5.13	-37.1%	$ 8.15

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 higher unit prices were attributable to increased demand for gas in the Pacific Northwest and additional transportation fees. The increase in quantities purchased was the result of increased wholesale sales discussed earlier.

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

The cost of gas purchased for resale decreased in 2002 as compared to 2001 primarily as a result of lower unit prices more than offsetting an increase in quantities. The significant gas price decreases are consistent with the increase in availability. Although there was a lower demand by retail customers as a result of warmer weather, SPPC sold more gas to wholesale customers causing the increase in quantity sold.

Deferral of Energy Costs—Net

	2003		2002		2001
(dollars in thousands)	**Amount**	**Change from Prior Year**	Amount	Change from Prior Year	Amount
Deferred energy costs—electric—net	**$ 1,982**	**N/A**	$(54,632)	-72.5%	$(198,826)
Deferred energy costs disallowed	**45,000**	**-21.0%**	56,958	N/A	—
Deferred energy costs—gas—net	**16,155**	**-34.8%**	24,785	N/A	(23,170)
Total	**$63,137**	**132.9%**	$ 27,111	N/A	$(221,996)

The increase in deferred energy costs—electric—net for the twelve months ended December 31, 2003, compared to the same period in 2002, resulted primarily from the deferral in the second quarter of 2002 of approximately $82 million for contract termination claims. Additionally, 2003 costs increased as a result of greater amortization of prior deferred energy costs compared to 2002. The 2003 increase in deferred energy costs was partially offset by an increase over 2002 in the amount that fuel and purchase power costs exceeded the recovery of those costs through rates. The change in Deferred energy costs—electric—net for the twelve months ended December 31, 2002 compared to the same period in 2001 reflects the amortization in 2002 of prior deferred costs pursuant to the PUCN's decision on SPPC's deferred energy rate case, which resulted in increased rates beginning June 1, 2002. The amortization was offset in part by the recording of current year deferrals of electric energy costs, reflecting the extent to which actual fuel and purchased power costs exceeded the fuel and purchased power costs recovered through current rates. During periods when actual fuel and purchase power costs exceed amounts recovered through rates, the excess is shown as a reduction in costs.

Deferred energy costs disallowed for the twelve months ended December 31, 2003, reflects a reduction in the deferral of energy costs incurred in the twelve months ended November 30, 2002 of $45 million, pursuant to a stipulation approved by the PUCN and effective June 1, 2003. Deferred energy costs disallowed for the twelve months ended December 31, 2002, reflects the write-off of $53 million of electric deferred energy costs, disallowed by the PUCN in their May 28, 2002 decision, and a write-off of $4 million in gas costs, disallowed by the PUCN in their December 23, 2002 decision on SPPC's Purchase Gas Adjustment rate case.

SPPC's Deferred energy costs—gas—net decreased for the twelve months ended December 31, 2003, primarily as a result of a decrease in the amount by which the recovery of natural gas costs through current rates exceeded the cost of natural gas incurred during 2003. The significant change from 2001 is attributed to lower gas costs in 2002 combined with the recovery of fuel and purchased power costs through current rates, which exceeded the actual fuel and purchase power costs.

Allowance For Funds Used During Construction (AFUDC)

	2003		2002		2001
(dollars in thousands)	**Amount**	**Change from Prior Year**	Amount	Change from Prior Year	Amount
Allowance for other funds used during construction	**$2,920**	**N/A**	$ 117	-86.3%	$ 856
Allowance for borrowed funds used during construction	**3,276**	**76.3%**	1,858	N/A	660
	$6,196	**N/A**	$1,975	30.3%	$1,516

AFUDC for SPPC is higher in 2003 compared to 2002 due to an increase in the AFUDC rates and an increase in construction work-in-progress (CWIP). AFUDC is higher in 2002 compared to 2001 due to an adjustment in 2001, which was made to refine amounts assigned to components of facilities that were completed in different periods. This increase was offset in part by a decrease in the AFUDC rate in 2002.

Other (Income) and Expenses

(dollars in thousands)	2003 Amount	2003 Change from Prior Year	2002 Amount	2002 Change from Prior Year	2001 Amount
Other operating expense	**$116,390**	**9.7%**	$106,122	-10.5%	$118,526
Maintenance expense	**$ 21,410**	**-7.9%**	$ 23,240	-4.6%	$ 24,363
Depreciation and amortization	**$ 81,514**	**6.7%**	$ 76,373	5.9%	$ 72,103
Income taxes	**$ (13,704)**	**98.0%**	$ (6,922)	N/A	$ 8,507
Interest charges on long-term debt	**$ 76,002**	**14.3%**	$ 66,474	13.1%	$ 58,797
Interest charges—other	**$ 23,367**	**119.1%**	$ 10,663	43.5%	$ 7,433
Interest accrued on deferred energy	**$ (5,163)**	**-51.5%**	$ (10,644)	-14.6%	$ (12,461)
Other income	**$ (4,403)**	**3.2%**	$ (4,266)	101.9%	$ (2,113)
Other expense	**$ 6,767**	**2.9%**	$ 6,577	6.5%	$ 6,176
Income taxes—other income and expense	**$ 1,467**	**-39.7%**	$ 2,431	N/A	$ (91)

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.

The decrease in Other operating expense for 2002 compared to 2001 reflects $8.6 million of provisions which were established in 2001 for retail uncollectible accounts. Additional factors that resulted in lower Other operating expenses during 2002 include the reversal of a $7.0 million provision originally established in 2001 pursuant to the PUCN order for costs associated with the conclusion of electric industry restructuring. SPPC had no 2002 short-term incentive plan expense compared to $4.2 million in 2001. Increases in Other operating expense during 2002 include $9.0 million in legal and advisory fees associated with liquidity issues and the consequences of the PUCN's deferred energy rate case decision.

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

Depreciation and amortization were higher in 2003 than 2002 due to an increase in plant-in-service. This increase was offset in part by an increase in 2002 depreciation of $1.8 million to reflect an adjustment to depreciation rates related to combustion turbines. Depreciation and amortization were higher in 2002 than 2001 due to an increase in plant-in-service.

As a result of net pretax losses from continuing operations recognized during 2002 and 2003, SPPC recorded an income tax benefit for those years. SPPC's income tax benefit for the year ended December 31, 2003 increased compared to the amount recognized during the same period in 2002. The change resulted from an increase in pretax losses. The increase in pretax losses resulted primarily from a decrease in operating revenue while incurring increases in operating expenses, depreciation and amortization, and interest expense.

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 long-term debt increased in 2002 compared to 2001 due to additional issuances of long-term debt at higher interest rates and the full year of interest incurred on $320 million of long-term debt issued in May 2001. In 2002, SPPC redeemed approximately $4 million in debt and issued additional debt of $100 million.

SPPC's Interest charges—other for the year ended December 31, 2003 increased compared to the same period in 2002. 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 case of Enron. See Note 15, Commitments and Contingencies, of Notes to Financial Statements for more information regarding the Enron litigation. Additionally, interest charges—other increased due to higher debt discount and expenses related to the issuance in October 2002 of $100 million of additional debt, an increase in interest on delayed/terminated contracts, and was reduced by the absence in 2003 of interest on short-term debt existing during the same period in 2002. Interest charges—other increased in 2002 compared to 2001 due to interest on extended payments to fuel and power suppliers resulting from renegotiated purchased power and fuel contracts, interest on short-term notes, and credit facility fees (refer to Liquidity and Capital Resources for further discussion of power and fuel contracts and the credit facilities).

Interest accrued on deferred energy costs decreased for the year ended December 31, 2003, compared to the same period in 2002 and for the year ended December 31, 2002, compared to the same period 2001 due to lower deferred fuel and purchased power balances during 2003. (Refer to Regulation and Rate Proceedings for discussion of deferred energy issues).

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

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. Other income for 2002 compared to 2001 increased due to increased interest and dividend income and gains on disposition of property.

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. Other expense increased in 2002 compared to 2001 due primarily to increased expenditures related to low-income energy assistance programs.

Taxes other than income taxes for the year ended December 31, 2003 were comparable to the amounts recognized during the same periods in 2002.

ANALYSIS OF CASH FLOWS

SPPC's cash flows were less during 2003 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 flows from investing activities decreased in 2003 because of additional cash requirements for construction activity during 2003. Cash flows from financing activities were lower primarily as a result of the cash provided in 2002 from the issuance of long-term debt, offset partially by reduced common dividend payments to SPR during 2003.

SPPC's net cash flows improved in 2002 compared to 2001, resulting primarily from an increase in cash flows from operating activities offset in part by a decrease in cash flows from investing activities. Although SPPC recorded a net loss during 2002 compared to net income in 2001 the current year's loss resulted largely from the write-off of disallowed deferred energy costs for which the cash outflow had occurred in 2001. Other factors contributing to 2002's improved cash flows from operating activities include the collection of deferred energy costs from customers and lower energy prices. Also, cash flows from operating activities in the current year reflect the receipt of an income tax refund. Cash flows from investing activities decreased in 2002 because 2001 investing activities included cash provided from the sale of the assets of SPPC's water business. Cash flows from financing activities during 2002 were comparable to 2001.

LIQUIDITY AND CAPITAL RESOURCES

SPPC had cash and cash equivalents of approximately $20.9 million at December 31, 2003 and $39.3 million at January 31, 2004.

As discussed in Construction Expenditures and Financing and Contractual Obligations, SPPC anticipates capital requirements for construction costs during 2004 totaling approximately $107 million, which SPPC expects to finance with internally generated funds, including the recovery of deferred energy. SPPC has $80 million of long-term debt that it will be required to remarket or purchase by May 3, 2004.

An increase in natural gas prices during SPPC's winter 2003-2004 peak season negatively impacted SPPC's cash flows, which SPPC addressed by issuing and selling its short-term $25 million Series F General and Refunding Mortgage Notes due March 31, 2004. In addition, SPPC entered into a $22 million short-term revolving Credit Agreement which expires March 31, 2004 to provide it with back-up liquidity during this winter peak season. SPPC has not and currently expects that it will not borrow any funds under this revolving credit facility.

Due primarily to SPPC's weakened financial condition, SPPC has been required to either pre-pay its power and natural gas purchases or make more frequent payments on its power and natural gas deliveries.

SPPC currently anticipates that based upon its current cash balance and expected cash flows leading up to the summer 2004 peak season, SPPC will not need additional liquidity to support its power and natural gas purchases. If SPPC has to pay higher than expected prices for fuel, natural gas and purchased power, if SPPC's suppliers require changes to SPPC's current payment terms, or if SPPC does not have sufficient available liquidity to obtain fuel and purchased power, particularly at the onset of their winter and summer peak seasons, SPPC may be required to issue or incur additional indebtedness, enter into additional liquidity facilities, or utilize its receivables purchase facility. Currently, SPPC is exploring the possibility of taking advantage of favorable conditions in the capital markets by entering into new financings to refinance existing debt on more favorable terms and to provide for additional or replacement back-up liquidity facilities. If SPPC is unable to enter into financings to provide it with sufficient additional liquidity and to repay its maturing indebtedness, whether due to unfavorable conditions in the capital markets, lack of regulatory authority to issue or incur such debt, credit downgrades by either S&P or Moody's resulting from the uncertainties discussed in this section, or restrictive covenants in certain of its financing agreements (see below), its ability to provide power and natural gas and fund its expected construction costs and its financial condition will be adversely affected.

Management has identified a number of other uncertainties that may have a negative impact on SPPC's financial condition and cash flows. The most significant of these uncertainties are:

- whether there will be any further requirements to pay the judgment of the Bankruptcy Court overseeing Enron's bankruptcy proceeding in favor of Enron or to provide further cash collateral, to secure the stay of the judgment against SPPC pending further appeal,
- whether SPPC will be able to recover regulatory assets in its current and future rate cases, especially previously incurred deferred fuel and purchased power costs, and to provide sufficient revenues to support its operations, and
- whether SPPC will be able to successfully refinance its maturing long-term debt and secure additional liquidity necessary to support its operations, including the purchase of fuel, power, and natural gas.

Because of the relationships among the uncertainties described above, an adverse development with respect to a combination of these uncertainties, could have a material adverse effect on SPPC's financial condition, results of operations and liquidity, and could make it difficult for SPPC to continue to operate outside of bankruptcy.

Effect of Rate Case Decisions

Credit Downgrades

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 29, 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. As a result of the downgrades, SPPC's ability to access the capital markets to raise funds is severely limited. Since SPR's credit ratings were similarly downgraded, SPR's ability to make capital contributions to SPPC also became severely limited.

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.

Power 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 15, Commitments and Contingencies of Notes to Financial Statements.

SPPC has established accrued liabilities, included in its Consolidated Balance Sheets as "Contract termination liabilities," of $105 million for terminated power supply contracts and associated interest. Correspondingly, pursuant to the deferred energy accounting provisions of AB 369, included in SPPC's deferred energy balances as of December 31, 2003, is approximately $84 million of charges associated with the terminated power supply contracts, deferred for recovery in rates in future periods.

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.

Accounts Receivable Facility

On October 29, 2002, SPPC established an accounts receivable purchase facility of up to $75 million. Actual amounts that may be advanced under the receivables purchase facilities will vary significantly depending upon, among other things, the time of year, the weather conditions and the delinquency notes of SPPC's receivables. Based on 2003 accounts receivables and the variables discussed above SPPC had a maximum capacity of $28 million and minimum capacity of $13 million under the receivables facility. The receivables purchase facility was renewed on October 28, 2003, and expires on October 26, 2004. If SPPC elects to activate the receivables purchase facility, SPPC will sell all of its accounts receivable generated from the sale of electricity and natural gas to customers to its newly created bankruptcy-remote special purpose subsidiary. The receivables sales will be without recourse except for breaches of customary representations and warranties made at the time of sale. The subsidiary will, in turn, sell these receivables to a bankruptcy-remote subsidiary of SPR. SPR's subsidiary will issue variable rate revolving notes backed by the purchased receivables.

The agreements relating to the receivables purchase facility contain various conditions to purchase, covenants and trigger events, and other provisions customary in receivables transactions. In addition to customary termination and mandatory repurchase events, the receivables purchase facility may terminate in the event that either SPPC or SPR defaults: (1) on the payment of indebtedness, or (2) on the payment of amounts due under a swap agreement, and such defaults aggregate to greater than $10 million and $5 million for SPPC and SPR, respectively.

Under the terms of the agreements relating to the receivables purchase facility, SPPC's facility may not be activated or, if activated, will be terminated in the event of a material adverse change in the condition, operations or business prospects of SPPC. In addition, the agreements contain a limitation on the payment of dividends by SPPC to SPR that is identical to the limitation contained in SPPC's Term Loan Agreement, described below. SPR has agreed to guaranty SPPC's performance of certain obligations as a seller and servicer under the receivables purchase facility.

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

SPPC has agreed to issue $75 million principal amount of its General and Refunding Mortgage Bonds upon activation of the receivables purchase facility. The full principal amount of the bond would secure certain of SPPC's obligations as seller and servicer, plus certain interest, fees and expenses thereon to the extent not paid when due, regardless of the actual amounts owing with respect to the secured obligations. As a result, in the event of an SPPC bankruptcy or liquidation, the holder of the bond securing the receivables purchase facility may recover more on a pro rata basis than the holders of other General and Refunding Mortgage securities, who could recover less on a pro rata basis, than they otherwise would recover. However, in no event will the holder of the bond recover more than the amount of obligations secured by the bond.

SPPC intends to use the accounts receivable purchase facility as a back-up liquidity facility and does not plan to activate this facility in the foreseeable future. SPPC may activate the facility within five days upon the delivery of certain customary funding documentation and the delivery of the $75 million General and Refunding Mortgage Bond. As of February 29, 2004, this facility had not been activated.

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, 2003, $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, 2003, $627 million of SPPC's General and Refunding Mortgage bonds 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 April 8, 2002.

On the basis of (1), (2), and (3) above, as of December 31, 2003, SPPC had the capacity to issue approximately $308 million of additional General and Refunding Mortgage securities, which amount does not include SPPC's $22 million Series G, General and Refunding Mortgage Note (discussed below) or the retirement of approximately $11 million of SPPC's $103 million Series E, General and Refunding Mortgage Bond (also discussed below).

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 SPPC's Term Loan Agreement and Receivable Purchase Facility Agreements limit the amount of additional indebtedness that SPPC may issue and the reasons for which such indebtedness may be issued. SPPC has reserved $75 million of General and Refunding Mortgage Bonds for issuance upon the initial funding of its receivables purchase facility.

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.

PUCN Order

On December 17, 2003, the PUCN issued an order in connection with its authorization of the issuance of short-term debt securities by NPC and SPPC. The PUCN order, for Dockets 03-10022 and 03-10023, permits NPC and SPPC to dividend an aggregate of $70 million per year to SPR through December 31, 2005. The PUCN order also provides that the dividend limitation may be reviewed in a subsequent application to grant short-term debt authority and that, in the event that exigent circumstances are experienced in the interim, either NPC or SPPC may petition the PUCN to review the dollar limitation.

Credit Facilities, Financing Transactions, and Covenants

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.

SPPC's Term Loan Agreement limits the amount of dividends that SPPC may pay to SPR. However, that 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) provided that those payments do not exceed $90 million, $80 million, and $60 million in the aggregate for the twelve month periods ending on October 30, 2003, 2004, and 2005, respectively.

The Term Loan Agreement also permits SPPC to make dividend payments to SPR in an aggregate amount not to exceed $10 million during the term of the Term Loan Agreement. In addition, SPPC may make dividend payments to SPR in excess of the amounts described above so long as, at the time of the payment and after giving effect to the payment, there are no defaults or events of default under the Term Loan Agreement, and such amounts, when aggregated with the amount of dividends paid to SPR by SPPC since the date of execution of the Term Loan Agreement, does not exceed the sum of:

(1) 50% of SPPC's Consolidated Net Income for the period commencing January 1, 2003 and ending with last day of fiscal quarter most recently completed prior to the date of the contemplated dividend payment, plus

(2) the aggregate amount of cash received by SPPC from SPR as equity contributions on its common stock during such period.

SPPC's Term Loan Agreement requires that SPPC maintain a ratio of consolidated total debt to consolidated total capitalization at all times during each of the following quarter in an amount not to exceed,

(1) .650 to 1.0 for the fiscal quarters ended December 31, 2002 through December 31, 2003,

(2) .625 to 1.0 for the fiscal quarters ended March 31, 2004 through December 31, 2004, and

(3) .600 to 1.0 for the fiscal quarter ended March 31, 2005 and for fiscal quarter thereafter.

SPPC's Term Loan Agreement also requires that SPPC maintain a consolidated interest coverage ratio for any four consecutive fiscal quarters ending with the fiscal quarter set for below of not less than,

(1) 1.75 to 1.0 for the fiscal quarters ended December 31, 2002, March 31, 2003, and June 30, 2003,

(2) 1.85 to 1.0 for the fiscal quarter ended September 30, 2003,

(3) 2.00 to 1.0 for the fiscal quarter ended December 30, 2003,

(4) 2.25 to 1.0 for the fiscal quarter ended March 31, 2004,

(5) 2.40 to 1.0 for the fiscal quarter ended June 30, 2004,

(6) 2.70 to 1.0 for the fiscal quarter ended September 30, 2004, and

(7) 3.00 to 1.0 for the fiscal quarter ended December 31, 2004 and for each fiscal quarter thereafter.

As of December 31, 2003, SPPC was in compliance with these financial covenants. The Term Loan Facility, which is secured by SPPC's $100 million Series C General and Refunding Mortgage Bond, will expire October 31, 2005. Currently, SPPC is exploring the possibility of taking advantage of favorable conditions in the capital markets by entering into new financings to refinance existing debt, including the Term Loan Facility, on more favorable terms. In the event that SPPC does refinance its Term Loan Facility, after the maturing of SPPC's Series F General and Refunding Mortgage Notes due March 31, 2004 and SPPC's Series G General and Refunding Mortgage Notes due March 31, 2004, the covenants in the Term Loan Facility will continue to remain in effect under the terms of SPPC's Series E General and Refunding Mortgage Bond (discussed below). If SPPC is unable to conform the terms of its Series E Bond to the more favorable terms of the refinancings or if SPPC is otherwise unable to modify the covenants in the Series E Bond, SPPC may encounter difficulty continuing to meet such covenants in future periods.

On May 1, 2003, 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 two-year 5.75% term rate to a 7.50% term rate for the period of May 1, 2003 to and including May 3, 2004. The bonds will be subject to remarketing on May 3, 2004 and will continue to be included in current maturities of long-term debt. 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 1, 2003 to and including May 3, 2004, SPPC's payment and purchase obligations in respect of the bonds are secured by SPPC's $80 million General and Refunding Mortgage Note, Series D, due 2004.

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. See Note 15, Commitments and Contingencies of Notes to Financial Statements for more information regarding the Enron litigation. The Series E Bond will be held in escrow until such time as the stay order is lifted, entry of an order affirming the judgment and a denial of stay of such order, or a settlement agreement is entered into between SPPC and Enron. SPPC expects to enter into a Remarketing Agreement with Enron and a Remarketing Agent which will provide for the possibility of the Series E Bond being remarketed in the event that the Series E Bond is released from escrow for the benefit of Enron. 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. The terms of the Series E Bond are substantially similar to SPPC's Term Loan Facility.

On December 22, 2003, SPPC issued and sold its $25 million General and Refunding Mortgage Notes, Series F, due March 31, 2004, to Merrill Lynch 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 are substantially similar to SPPC's Term Loan Facility.

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 will be used to provide back-up liquidity for SPPC during its 2003-2004 winter peak. Currently, SPPC does not expect to borrow under this facility. The terms of the Series G Note are substantially similar to SPPC's Term Loan Facility.

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

Cross-Default Provisions

Certain financing agreements of SPPC contain cross-default provisions that would result in an event of default under such financing agreements if there is a failure under other financing agreements of SPPC and SPR 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 or SPR 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 $627 million of securities outstanding as of December 31, 2003, provides for an event of default if a matured event of default under SPPC's First Mortgage Indenture occurs;
- SPPC's Term Loan Agreement, Series E Bond, Series F Notes and Series G Note provides for an event of default if (a) SPPC or any of its subsidiaries default (i) in the payment of indebtedness, or (ii) in the payment of amounts due under hedge agreements, and such defaults aggregate to greater than $10 million, or (b) SPPC's General and Refunding Mortgage Indenture ceases to be enforceable; and
- SPPC's receivables purchase facility may terminate in the event that either SPPC or SPR defaults (i) in the payment of indebtedness, or (ii) in the payment of amounts due under hedge agreements, and such defaults aggregate to greater than $10 million and $5 million for SPPC and SPR, respectively.

Judgment Related Defaults

SPPC's $100 million Term Loan Agreement, $103 million Series E General and Refunding Mortgage Bond, $25 million Series F General and Refunding Mortgage Notes, and Series G Note in the maximum principal amount of $22 million, provide for an event of default if a judgment of $10 million or more is entered against SPPC and such judgment is not vacated, discharged, stayed or bonded pending appeal within 30 days. The Term Loan Agreement and the Series E Bond, Series F Notes, and Series G Note also prohibit the creation or existence of any liens on SPPC's properties except for liens specifically permitted under the Term Loan Agreement or the Series E Bond, Series F Notes, and Series G Note. If a judgment lien is filed against SPPC, the filing of the lien will trigger an event of default under the Term Loan Agreement and the Series E Bond, Series F Notes, and Series G Note. Upon an event of default, the Administrative Agent under the Term Loan Agreement may, upon request of more than 50% of the lenders under the Term Loan Agreement, declare all amounts due under the Term Loan Agreement immediately due and payable. Currently, SPPC has $99 million outstanding under its Term Loan facility. A similar acceleration provision applies to the Series E Bond, Series F Notes, and Series G Note.

SPPC's obligations under the Term Loan Agreement are secured by a General and Refunding Mortgage Bond and SPPC's Series E Bond, Series F Notes, and Series G Note were issued under NPC's General and Refunding Mortgage Indenture. If SPPC fails to repay all amounts due upon an acceleration under the Term Loan Agreement or the applicable series of securities within 3 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.

In the event that SPPC's Term Loan or its Series E Bond, Series F Notes, or Series G Note is accelerated and results in the acceleration of all amounts outstanding under SPPC's 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.

Limitations on Indebtedness

The terms of SPPC's $100 million Term Loan Facility, which expires October 31, 2005, and its Series E Bond, Series F Notes due March 31, 2004, and Series G Note due March 31, 2004 restrict SPPC from issuing additional indebtedness unless the debt issued is specifically permitted, which includes certain letter of credit indebtedness, certain capital lease obligations, indebtedness incurred to refinance existing indebtedness, certain intercompany indebtedness, certain letters of credit issued to support SPPC's obligations with respect to energy suppliers, and a limited amount of general indebtedness.

If SPPC is unable to access the capital markets to issue additional indebtedness to support its operations, including the purchase of fuel and power, and to refinance its existing indebtedness, whether due to lack of access to the capital markets, lack of regulatory authority, or restrictive covenants in its Term Loan Agreement, Series E Bond, Series F Notes, and Series G Note, its ability to provide power and its financial condition will be adversely affected.

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 2004 by approximately $5.3 million over the 2003 cost of $35.5 million. As of September 30, 2003, the measurement date, the plan had assets with a fair value that was less than the present value of the accumulated benefit obligation under the plan. During 2003, SPPC contributed a total of $11.9 million to meet its funding obligations under the plan. At the present time it is not expected that any near term funding obligations will have a material adverse effect on liquidity.

Construction Expenditures and Financing

The table below provides an overview of SPPC's consolidated cash construction expenditures and internally generated cash, net for 2001 through 2003 (dollars in thousands):

	2003	2002	2001
Cash construction expenditures	**$123,529**	$ 93,033	$ 105,129
Net cash flow from operating activities	**$ 72,111**	$173,600	$(211,699)
Common and preferred cash dividends paid	**22,430**	48,805	89,901
Internally generated cash	**49,681**	124,795	(301,600)
Investment by parent company	**—**	10,000	104,948
Total cash available	**$ 49,681**	$134,795	$(196,652)
Internally generated cash as a percentage of cash construction expenditures	**40%**	134%	N/A
Total cash generated (used) as a percentage of cash construction expenditures	**40%**	145%	N/A

SPPC's estimated cash construction expenditures for 2004 through 2008 are $470.8 million. Construction expenditures for 2004 are projected to be approximately $107 million and are expected to be financed by internally generated funds, including the recovery of deferred energy costs.

Cash provided by internally generated funds during 2004 assumes, among other things, that SPPC will be able to refinance its debt maturing in 2004, that SPPC will not be required to make any significant unanticipated cash outlays including additional payments of collateral into the escrow account established in connection with the Enron judgment, that there will be no material disallowances in SPPC's 2003 deferred energy rate case and its 2004 general rate case, that SPPC will not have to pay higher than expected prices for fuel, natural gas and purchased power and that SPPC's current payment terms with its suppliers will remain unchanged. See Regulation Proceedings, Nevada Matters for additional information regarding the recently filed rate cases and prior rate case and Liquidity and Capital Resources for additional information regarding NPC's liquidity condition and cash flows.

In the event that SPPC is unable to finance its construction expenditures with internally generated funds, SPPC may need to raise all or a portion of the necessary funds through the capital markets or from activating its accounts receivables purchase facility to provide additional liquidity. For additional information regarding the accounts receivables purchase facility, see Liquidity and Capital Resources. SPPC may activate its receivables purchase facility within five days upon the delivery of certain customary funding documentation and the delivery of $75 million of its General and Refunding Mortgage Bonds to secure the facility. If a material adverse event were to occur, it could potentially trigger a termination event with respect to the receivables facility and would also make it more difficult for SPPC to access the capital markets for any such financing needs.

Contractual Obligations

The table below provides SPPC's contractual obligations, not including estimated construction expenditures described above, as of December 31, 2003, 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

	2004	2005	2006	2007	2008	Thereafter	Total
Long-Term Debt	$ 83,400	$100,400	$ 52,400	$ 2,400	$322,400	$ 437,850	$ 998,850
Long-Term Debt Interest	69,515	39,452	39,420	36,008	125,608	514,465	824,468
Purchased Power	57,030	29,385	29,969	30,767	32,259	5,540	184,950
Coal and Natural Gas	163,544	75,587	71,191	52,822	45,684	255,662	664,490
Operating Leases	8,152	7,553	7,197	5,965	5,966	22,153	56,986
Total Contractual Cash Obligations	$381,641	$252,377	$200,177	$127,962	$531,917	$1,235,670	$2,729,744

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

Capital Structure

As of December 31, 2003, SPPC had $25 million of short-term debt outstanding and $83.4 million of current maturities of long-term debt.

For a complete discussion of the SPPC financing transactions please see both the Accounts Receivable Facility and the Financing Transactions sections of the Liquidity and Capital Resources—SPPC discussion.

SPPC's actual capital structure at December 31, 2003, and 2002 was as follows (dollars in thousands):

	2003		2002	
Short-Term Debt[1]	**$ 108,400**	**7%**	$ 101,400	6%
Long-Term Debt	**912,800**	**54%**	914,788	54%
Preferred Stock	**50,000**	**3%**	50,000	3%
Common Equity	**593,771**	**36%**	639,295	37%
TOTAL	**$1,664,971**	**100%**	$1,705,483	100%

(1) Including current maturities of long-term debt.

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 amongst 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.

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 expects to file its IRP in July 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 2004 through 2005 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 at least annually.

NPC's energy supply plan was filed with the PUCN on July 1, 2003 with NPC's 2003-2022 IRP. The IRP was approved by the PUCN on November 12, 2003. SPPC's plan is in the final stages of development and will be filed with the PUCN for informational purposes.

The key features of the IRP that were approved by the PUCN include:

- Approval of NPC's plan to reserve up to 650 MW of additional native load transmission rights on the Centennial Transmission Project,
- Approval for re-conductoring the 230 kV Mead system that would increase system import by 450 MW at an estimated cost of $24 million,
- Approval to construct a combustion turbine at the Harry Allen site at an estimated cost of $44 million,
- Approval to construct a combined cycle plant rate at 520 MW at the Harry Allen site at an estimated cost of $415 million,
- Approval to study a coal generation plant for $500,000,
- Approval to conduct generation siting study at a estimated cost of $400,000,
- Approval to conduct generation life assessment study at a cost of $500,000 per year over the next five years,
- Approval to spend $9.2 million, $9.3 million, and $9.3 million for the calendar years 2004, 2005, and 2006 respectively for demand side programs,
- Approval of the recommended Natural Gas hedging strategy, and
- Approval to conduct two long-term purchase power requests for proposals. One for renewable to comply with the state law requiring a renewable portfolio standard and one for all bidders to fill up to 1,500 MW.

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).

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

SPPC's energy supply plan will have many of the same features of NPC's plan with respect to managing fuel and purchased power cost and risk exposure, but SPPC's plan is being specifically tailored to its load obligation and the energy supply characteristics of its sub-region.

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. Deliveries of power to NPC will begin on the first day of the month following PUCN approval.

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 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 statute (NRS 704.110(3)). NPC's analysis and presentation of the costs of providing electric service (exclusive of purchased fuel and purchased power) indicated that it is necessary to increase the revenue requirement for general rates by $142 million annually. Factors supporting the requested revenue increase included:

- investments in infrastructure of $433 million since the last general rate case,
- a requested Return on Equity (ROE) of 12.4%, and Rate of Return (ROR) 10.0%,
- recovery of the costs to merge NPC and SPPC,
- recovery of the costs NPC spent on the generation divestiture project, which was cancelled by legislation,
- a return on the cash balances NPC must maintain to provide continuous service, and
- increased operating costs.

NPC is recommending that the PUCN authorize a deferred collection of the increase to reduce customers' rate volatility. Specifically NPC requested a $50 million (computed on an annual revenue basis) or 3.4% rate increase to commence on April 1, 2004 and for this initial increase, to continue for nine months. Beginning January 1, 2005, coincident with a requested deferred energy rate reduction resulting from the expected payoff of the 2001 deferred account balances, annualized general revenue would then increase by $92 million plus the amount necessary to return $76 million over the following 15 months. The requested increase in general rates is expected to be offset by the requested decrease in general rates. This $76 million is the estimated amount being deferred ($73 million plus interest of $3 million) during the prior nine month period between April 1, 2004 and January 1, 2005.

NPC updated the General Rate Case filing with its Certification filing dated December 14, 2003. The certification filing reduced NPC's request from $142 million to $133 million. Interveners' testimony, received in late January 2004 recommends reductions to NPC's request including lower ROEs ranging between 8.10% and 10.71% disallowance of certain costs including merger related costs and goodwill, changes to amortizations of regulatory assets, exclusion of certain plant and other assets, etc. The testimony recommends ranges from $1 million in reduced general rates to $17 million in increased general rates as compared to NPC's requested increase of $133 million. During the course of hearing, NPC agreed to approximately $18 million in reductions to its request for various items. Hearings were completed on February 12, 2004, and a decision is expected during the later part of March 2004.

Nevada Power Company 2001 General Rate Case

On October 1, 2001, NPC filed an application with the PUCN, as required by law, seeking an electric general rate increase. On December 21, 2001, NPC filed a certification to its general rate filing updating costs and revenues pursuant to Nevada regulations. In the certification filing, NPC requested an increase in its general rates charged to all classes of electric customers designed to produce an increase in annual electric revenues of $22.7 million, or an overall 1.7% rate increase. The application also sought a return on common equity (ROE) for NPC's total electric operations of 12.25% and an overall rate of return (ROR) of 9.30%.

On March 27, 2002, the PUCN issued its decision on the general rate application, ordering a $43 million revenue decrease with an ROE of 10.1% and ROR of 8.37%. The effective date for the decision was April 1, 2002. The decision also resulted in adjustments increasing accumulated depreciation by $6.7 million, and the inclusion of approximately $5 million of revenues related to SO2 allowances. The PUCN delayed consideration of recovery of SPR/NPC merger costs until a future rate case. NPC was not granted a carrying charge on these deferred costs. Recovery of costs related to the generation divestiture project, which supported Nevada's now-abandoned utility restructuring policy, were also delayed. A carrying charge was allowed by the PUCN for the delayed recovery of divestiture costs. NPC renewed its request to recover merger related and divestiture costs in its general rate case which was filed on October 1, 2003.

On April 15, 2002, NPC filed a petition for reconsideration with the PUCN. On May 24, 2002, the PUCN issued an order on the petition for reconsideration. The PUCN modified its original order reversing the adjustment to accumulated depreciation of $6.7 million, and decreased the SO2 allowance revenue amortization to $3.2 million per year. Revised rates for these changes went into effect on June 1, 2002.

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, together with a carrying charge to be recovered based on an asymmetric amortization that would result in the recovery of $14 million in the first year and

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

$39.5 million in each of the next two years. The application also requested an increase to the going-forward rate for energy. The combined effect of these two adjustments resulted in a request for an overall rate increase of 5.74%. In their testimony, various interveners recommended a proposed disallowance from $23 million to $39 million, reductions and changes to deferred rates proposed to recover costs in this case and prior cases, and disagreed with NPC's proposal to gross-up the equity portion of carrying charges for income taxes. The PUCN is expected to rule on this filing the later part of March 2004.

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. The PUCN and NPC are expected to file responding briefs on March 9, 2004. The court has not 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 Commission 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. The Settlement Judge has yet to recommend closure of the settlement process given current caseloads at the Supreme Court. Briefing, oral argument and a decision are not expected to occur until 2005. NPC is not able to predict the outcome of the process or of the Supreme Court's deliberation on the matter.

Nevada Power Company 2003 IRP

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

The IRP also includes a three-year action plan that covers calendar years 2004, 2005, and 2006. During this period, NPC proposes a number of specific projects to be completed. NPC proposes 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 will 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 may need to expend up to approximately $500 million prior to the summer of 2007 for the construction and/or acquisition of generation facilities. If NPC is unable to provide this amount with internally generated funds, it may need to access the capital markets to do so.

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.

On December 23, 2003, NPC filed its first amendment to the Supply-Side Action Plan previously approved in NPC's 2003 IRP. In the application NPC is seeking approval from the Commission for a long-term purchase obligation of approximately 224 MW of capacity dispatchable seven days a week and twenty-four hours a day with Las Vegas Cogeneration II. On February 13, 2004, a stipulation was filed with the PUCN that included the long-term purchase obligation. The PUCN is expected to issue a decision on the stipulation in early March 2004.

Nevada Power Company Additional Finance Authority

$235 Million Long-Term Debt Authority

On September 26, 2003, NPC filed an application with the PUCN for authority to issue secured long-term debt in an aggregate amount not to exceed $235 million through the period ending October 30, 2005. This authority was requested to support a stay of the judgment in the Enron matter against NPC by the U.S. Bankruptcy Court of the Southern District of New York. This matter was designated as Docket Number 03-9027, and the PUCN consolidated this docket with the related SPPC Docket Number 03-9026.

On October 30, 2003, the PUCN issued an Interim Order granting the authority to issue up to $235 million in secured long-term debt securities to be issued as collateral to support a stay of judgment of the Bankruptcy Court. Further, the PUCN noted that no party is barred from questioning the reasonableness or prudence of any action undertaken by NPC pursuant to this authority, nor does the authority in any way indicate the ratemaking treatment to be afforded expenses related to this authority.

The PUCN noted that, while the use of a secured bond as collateral for the judgment would not affect NPC's balance sheet, the sale of such bond would have such an effect. Accordingly, the PUCN directed NPC that, as soon as NPC determines that it is likely that the bonds will be sold, NPC shall report those developments in detail in a filing with the PUCN so that they can convene a hearing prior to the sale of the debt. This ruling was later confirmed in a PUCN order issued December 3, 2003.

$250 Million Short-Term Debt Authority

On October 9, 2003, NPC filed an application with the PUCN for authority to issue secured or unsecured short-term debt securities in an aggregate amount not to exceed $250 million through the period ending December 31, 2005. This authority was requested to replace the existing short-term debt authority that expired on December 31, 2003. This matter was designated as Docket Number 03-10023, and the PUCN consolidated this docket with the related SPPC Docket Number 03-10022.

On December 17, 2003, the PUCN issued an order granting NPC the authority to issue up to $250 million in short-term secured or unsecured debt securities, such authority to expire December 31, 2005. In that order the PUCN also removed the NPC dividend restriction that had been put into place in the Compliance Order for Docket No. 02-4037. Rather, in this docket the PUCN has placed a limitation on total dividends that may be made to SPR. The PUCN limited cash dividends from NPC and SPPC to an aggregate total of $70 million per year from NPC and/or SPPC to SPR until December 31, 2005. It also indicated that the dividend limitation may be reviewed in a subsequent application to grant additional short-term debt authority, and also granted NPC leave to petition the PUCN to review the dollar limitation in the event exigent circumstances are experienced in the interim.

Additionally, the PUCN found that the prudency of any action pursuant to the authority granted would be subject to future review and to demonstration that the actions taken were reasonable. They further ordered that any proceeds obtained pursuant to the granted authority are to be used only for utility purposes in NPC's service territory.

NPC Application for $230 Million Long-Term Debt Authority

On January 21, 2004, NPC filed an application with the PUCN for authority to issue secured long-term debt in an aggregate amount not to exceed $230 million through the period ending December 31, 2004. This authority was requested to allow for the refinancing of existing debt securities, as well as to provide additional liquidity to support utility operations. This matter was designated as Docket Number 04-1014. A hearing on this matter is scheduled for March 2004.

Sierra Pacific Power Company 2003 General Rate Case

On December 1, 2003, as required by law, SPPC filed an application with the PUCN seeking an electric general rate increase. In the filing, SPPC requested an increase in its general rates charged to all classes of electric customers, which were designed to produce an increase in annual electric revenues of approximately $95 million representing an overall 13.13% rate increase. The application seeks a ROE for SPPC's total electric operations of 12.4% and an overall ROR of 10.11%. SPPC has also asked for a staggered implementation of the overall revenue requirement. If approved SPPC would implement $70 million of the requested $95 million the first year, delaying the other $25 million, plus an amount necessary to return those dollars deferred the first year, until the next year. A pre-hearing conference was held on January 16, 2004. Evidentiary hearings are scheduled to begin on April 1, 2004 and the PUCN is expected to rule on this filing in May 2004.

Sierra Pacific Power Company 2001 General Rate Case

On November 30, 2001, as required by law, SPPC filed an application with the PUCN seeking an electric general rate increase. On February 28, 2002, SPPC filed a certification to its general rate filing, updating costs and revenues pursuant to Nevada regulations. In the certification filing, SPPC requested an increase in its general rates charged to all classes of electric customers, which were designed to produce an increase in annual electric revenues of $15.9 million representing an overall 2.4% rate increase. The application also sought an ROE for SPPC's total electric operations of 12.25% and an overall ROR of 9.42%.

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

On May 28, 2002, the PUCN issued its decision on the general rate application, ordering a $15.3 million revenue decrease with an ROE of 10.17% and ROR of 8.61%. The effective date of the decision was June 1, 2002. The PUCN delayed consideration of recovery of SPR/NPC merger costs until a future rate case, and SPPC was not granted a carrying charge on these deferred costs. Recovery of costs related to the generation divestiture project, which supported Nevada's now-abandoned utility restructuring policy, were delayed. A carrying charge was allowed by the PUCN for the delayed recovery of divestiture costs. SPPC renewed its request to recover merger and divestiture costs in its general rate case which was filed on December 1, 2003.

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 requests a deviation from regulation and historic practice and to put in place an asymmetric amortization of the deferred energy balance of approximately $42 million, that would result in recovery of $8 million effective July 2004; $17 million effective July 2005; and $17 million effective July 2006. The Application also requests a deviation from regulation in resetting the BTER (Base Tariff Energy Rate). That methodology and its results would result in no change to the currently effective BTER. The PUCN is expected to rule on this filing in July 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 Bureau of Consumer Protection 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 Base Tariff Energy Rate 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.

Sierra Pacific Power Company Additional Finance Authority

$103 Million Long-Term Debt Authority

On September 26, 2003, SPPC filed an application with the PUCN for authority to issue secured long-term debt in an aggregate amount not to exceed $103 million through the period ending October 30, 2005. This authority was requested to support a stay of the judgment in the Enron matter against SPPC by the U.S. Bankruptcy Court of the Southern District of New York. This matter was designated as Docket Number 03-9026, and the PUCN consolidated this docket with the related SPPC Docket Number 03-9027.

On October 30, 2003, the PUCN issued an Interim Order granting the authority to issue up to $103 million in secured long-term debt securities to be issued as collateral to support a stay of judgment of the Bankruptcy Court. It also found that the issue of dividend restrictions, raised by the intervener Southern Nevada Water Authority (SNWA) was not appropriate for this docket. Further, the PUCN noted that no party is barred from questioning the reasonableness or prudence of any action undertaken by SPPC pursuant to this authority, nor does the authority in any way indicate the ratemaking treatment to be afforded expenses related to this authority.

The PUCN noted that, while the use of a secured bond as collateral in this matter would not affect the Company's balance sheet, the issuance and sale of securities related to the bond would have such an effect. Accordingly, the PUCN directed SPPC that, as soon as the SPPC determines that it is likely that the bonds issued will have to be sold and the debt incurred, the SPPC shall report those developments in detail in a filing with the PUCN so that they can convene a hearing prior to the sale of the debt. This ruling was later confirmed in a PUCN order issued December 3, 2003.

$250 Million Short-Term Debt Authority

On October 9, 2003, SPPC filed an application with the PUCN for authority to issue secured or unsecured short-term debt securities in an aggregate amount not to exceed $250 million through the period ending December 31, 2005. This authority was requested to replace the existing short-term debt authority that expired on December 31, 2003. This matter was designated as Docket Number 03-10022, and the PUCN consolidated this docket with the related NPC Docket Number 03-10023.

On December 17, 2003, the PUCN issued an order granting SPPC the authority to issue up to $250 million in short-term secured or unsecured debt securities, such authority to expire December 31, 2005. In addition, in this docket the PUCN has placed a limitation on total dividends that may be made to the parent company SPR. The PUCN limited cash dividends from NPC and SPPC to an aggregate total of $70 million per year from NPC and/or SPPC to SPR until December 31, 2005. It also indicated that the dividend limitation may be reviewed in a subsequent application to grant additional short-term debt authority, and also granted SPPC leave to petition the PUCN to review the dollar limitation in the event exigent circumstances are experienced in the interim.

Additionally, the PUCN found that the prudency of any action pursuant to the authority granted would be subject to future review and to demonstration that the actions taken were reasonable. They further ordered that any proceeds obtained pursuant to the granted authority are to be used only for utility purposes in SPPC's service territory.

SPPC Application for $230 Million Long-Term Debt Authority

On December 31, 2003, SPPC filed an application with the PUCN for authority to issue secured long-term debt in an aggregate amount not to exceed $230 million through the period ending December 31, 2004. This authority was requested to allow for the refinancing and remarketing of existing debt securities, as well as to provide additional liquidity to support utility operations. This matter was designated as Docket Number 03-12030. A hearing on this matter is scheduled for late March 2004.

Annual Purchased Gas Cost Adjustment 2003 (SPPC)

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 Balancing Account Adjustment (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 Bureau of Consumer Protection 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 will 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 $0.66375 per therm was approved, an increase from the previous BPGR of $0.05316 per therm. The new rates were implemented November 1, 2003.

Annual Purchased Gas Cost Adjustment 2002 (SPPC)

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 Base Purchased Gas Rate (BPGR) and an increase in its Balancing Account Adjustment charge (BAA) 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.

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

California Matters (SPPC)

Rate Stabilization Plan

SPPC serves approximately 44,500 customers in California. 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 periodic 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 which included an increase of $3.02 million or 5.8%, adopted a rate design methodology and reinstituted the Energy Cost Adjustment (ECAC) mechanism. The rate increase was effective January 16, 2004.

Open Access Transmission Tariff

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 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 have 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. The Utilities have not yet received final approval of the refund report.

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. A procedural schedule was issued that included a settlement conference on January 21, 2004, and pre-trial briefs due on June 4, 2004.

RECENT PRONOUNCEMENTS

On June 25, 2003, the Derivatives Implementation Group of the FASB (DIG) issued Statement 133 Implementation Issue No. C20 (C20). C20 addresses contracts with price adjustment features that are not clearly and closely related to the asset being sold or purchased, and whether that would preclude the use of the normal purchases and normal sales scope exception provided in paragraph 10(b) of SFAS 133. Management has concluded that this scope exception continues to apply to NPC's and SPPC's power contracts, as such it does not have an effect on NPC's or SPPC's financial position or results of operations.

The DIG revised Statement 133 Implementation Issue No. C15 (C15) on November 5, 2003. C15, which was originally issued June 27, 2001, and revised December 19, 2001, addresses the normal purchases and normal sales scope exceptions for option-type contracts and forward contracts in electricity. It defines capacity contracts, that continue to receive the scope exception, and financial option contracts that do not. Management has concluded that the current classifications of such contracts for purposes of mark to market valuations follow the revised guidelines specified in C15.

The Emerging Issues Task Force of the FASB (EITF) reached consensus on Issue No. 03-11 (EITF 03-11) on July 31, 2003. EITF 03-11 addresses gross versus net treatment on gains and losses of derivative instruments held for trading purposes, and those that are settled physically. NPC and SPPC's derivative instruments are held solely for the mitigation of price risk associated with power contracts and, as explained in Note 11, Derivative and Hedging Activities, all gains and losses are recorded as risk management regulatory liabilities and risk management regulatory assets on the balance sheet due to deferred energy accounting. EITF 03-11 did not have an effect on NPC's or SPPC's financial position or results of operations.

In November 2002, the Financial Accounting Standards Board (FASB) issued Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees" (FIN 45), which elaborates on the disclosures to be made in interim and annual financial statements of a guarantor about its obligations under certain guarantees that it has issued. It also clarifies that a guarantor is required to recognize, at the inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing a guarantee. Initial recognition and measurement provisions of FIN 45 are applicable on a prospective basis to guarantees issued or modified after December 31, 2002. The disclosure requirements were effective for financial statements of interim or annual periods beginning January 1, 2003. As of December 31, 2003, all guarantees of SPR and its subsidiaries were intercompany, whereby the parent issued the guarantees on behalf of its consolidated subsidiaries to a third party. Therefore, there was no impact on the financial position, results of operation or cash flows of SPR, NPC, or SPPC as a result of the adoption.

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

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, 2003							
Expected Maturity Date	2004	2005	2006	2007	2008	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%	0.00%	7.93%	0.00%	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%	6.86%	7.31%	
TOTAL DEBT	$233,079	$400,415	$ 52,415	$242,635	$322,413	$2,586,398	$3,837,355	$4,112,028

	December 31, 2002							
Expected Maturity Date	2003	2004	2005	2006	2007	Thereafter	Total	Fair Value
LONG-TERM DEBT								
SPR								
Fixed Rate	$ 16,886	$ 14,498	$300,000	$ —	$345,000	$ —	$ 676,384	$ 527,432
Average Interest Rate	8.00%	8.00%	8.75%	0.00%	7.93%	0.00%	8.17%	
Variable Rate	$200,000						$ 200,000	$ 142,000
Average Interest Rate	2.49%						2.49%	
NPC								
Fixed Rate	$210,013	$130,013	$ 15	$ 15	$ 17	$1,383,561	$1,723,634	$1,515,767
Average Interest Rate	6.00%	6.20%	8.17%	8.17%	8.17%	7.88%	7.43%	
Variable Rate	$140,000					$ 115,000	$ 255,000	$ 243,800
Average Interest Rate	3.59%					1.74%	2.67%	
SPPC								
Fixed Rate	$101,400	$ 3,400	$100,400	$ 52,400	$ 2,400	$ 760,250	$1,020,250	$ 947,315
Average Interest Rate	5.77%	7.39%	10.39%	6.71%	6.10%	7.34%	7.28%	
TOTAL DEBT	$668,299	$147,911	$400,415	$ 52,415	$347,417	$2,258,811	$3,875,268	$3,376,314

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

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 Management's Discussion and Analysis of Financial Condition and Results of Operations, for a discussion of the Utilities' purchased power procurement strategies and Note 15, 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 $877,000 as of December 31, 2003. 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.

INDEPENDENT AUDITORS' REPORT

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, 2003 and 2002, 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, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Sierra Pacific Resources and subsidiaries as of December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America.

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

As discussed in Note 1 to the consolidated financial statements, during 2003 the Company changed the classification of asset removal costs as a result of the adoption of Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations."

Deloitte & Touche LLP

Reno, Nevada
March 7, 2004

INDEPENDENT AUDITORS' REPORT

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, 2003 and 2002, 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, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Nevada Power Company and subsidiaries as of December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the consolidated financial statements, during 2003 the Company changed the classification of asset removal costs as a result of the adoption of Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations."

Deloitte & Touche LLP

Reno, Nevada
March 7, 2004

INDEPENDENT AUDITORS' REPORT

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, 2003 and 2002, 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, 2003. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Sierra Pacific Power Company and subsidiaries as of December 31, 2003 and 2002, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the consolidated financial statements, during 2003 the Company changed the classification of asset removal costs as a result of the adoption of Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations."

Deloitte & Touche LLP

Reno, Nevada
March 7, 2004

CONSOLIDATED BALANCE SHEETS—SIERRA PACIFIC RESOURCES

December 31,	2003	2002
(dollars in thousands)		
ASSETS		
Utility Plant at Original Cost:		
Plant-in-service	**$6,353,399**	$5,989,701
Less accumulated provision for depreciation	**1,953,271**	1,792,700
	4,400,128	4,197,001
Construction work-in-progress	**242,522**	263,346
	4,642,650	4,460,347
Investments and other property, net	**109,642**	130,421
Current Assets:		
Cash and cash equivalents	**181,789**	192,064
Restricted cash (Note 1)	**54,705**	13,705
Accounts receivable less allowance for uncollectible accounts: 2003—$44,917; 2002—$44,184	**301,615**	358,972
Deferred energy costs—electric	**295,677**	268,979
Deferred energy costs—gas	**1,358**	17,045
Materials, supplies and fuel, at average cost	**80,941**	87,348
Risk management assets (Note 11)	**22,099**	29,570
Deposits and prepayments for energy	**63,847**	17,194
Other	**34,832**	31,704
	1,036,863	1,016,581
Deferred Charges and Other Assets:		
Goodwill (Note 1)	**309,971**	309,971
Deferred energy costs—electric	**497,905**	685,875
Regulatory tax asset	**155,547**	163,889
Other regulatory assets (Note 1)	**142,507**	136,933
Risk management regulatory assets—net (Note 11)	**14,283**	44,970
Unamortized debt issuance expense	**50,842**	49,804
Other	**103,548**	98,986
	1,274,603	1,490,428
Assets of Discontinued Operations (Note 19)	**—**	12,862
	$7,063,758	$7,110,639

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

(continued)

CONSOLIDATED BALANCE SHEETS—SIERRA PACIFIC RESOURCES (continued)

December 31,	**2003**	2002
(dollars in thousands)		
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Common shareholders' equity	**$1,435,394**	$1,327,166
Preferred stock	**50,000**	50,000
Long-term debt	**3,579,674**	3,257,596
	5,065,068	4,634,762
Current Liabilities:		
Short-term borrowings	**25,000**	—
Current maturities of long-term debt	**238,636**	672,895
Accounts payable	**166,440**	232,424
Accrued interest	**62,199**	44,744
Dividends declared	**1,046**	1,045
Accrued salaries and benefits	**24,428**	20,798
Deferred federal income taxes	**133,844**	123,507
Risk management liabilities (Note 11)	**16,540**	69,953
Contract termination liabilities (Note 15)	**338,704**	—
Other current liabilities	**44,987**	46,719
	1,051,824	1,212,085
Commitments & Contingencies (Note 15)		
Deferred Credits and Other Liabilities:		
Deferred federal income taxes	**271,091**	336,875
Deferred investment tax credit	**45,329**	48,492
Regulatory tax liability	**41,877**	42,718
Customer advances for construction	**126,506**	116,032
Accrued retirement benefits	**112,075**	163,752
Risk management liabilities (Note 11)	**—**	3,917
Contract termination liabilities (Note 15)	**45,766**	318,158
Regulatory liabilities (Note 1)	**218,158**	28,904
Accrued removal costs	**—**	151,651
Other	**86,064**	52,506
	946,866	1,263,005
Liabilities of Discontinued Operations (Note 19)	**—**	787
	$7,063,758	$7,110,639

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

CONSOLIDATED STATEMENTS OF OPERATIONS— SIERRA PACIFIC RESOURCES

Year ended December 31,	**2003**	2002	2001
(dollars in thousands, except per share amounts)			
OPERATING REVENUES:			
Electric	**$ 2,624,426**	$ 2,832,285	$ 4,426,881
Gas	**161,586**	149,783	145,652
Other	**3,146**	3,236	2,728
	2,789,158	2,985,304	4,575,261
OPERATING EXPENSES:			
Operation:			
Purchased power	**1,104,344**	1,786,823	4,052,077
Fuel for power generation	**521,412**	453,436	728,619
Gas purchased for resale	**111,675**	91,961	136,534
Deferred energy costs disallowed	**90,964**	491,081	—
Recovery (Deferral) of energy costs—electric—net	**97,893**	(233,814)	(1,136,148)
Recovery (Deferral) of energy costs—gas—net	**16,155**	24,785	(23,170)
Impairment of subsidiary assets (Note 19)	**32,911**	—	—
Other	**328,962**	287,422	319,107
Maintenance	**69,636**	64,440	69,499
Depreciation and amortization	**191,940**	174,726	165,808
Taxes:			
Income tax benefit	**(70,138)**	(167,935)	(1,764)
Other than income	**45,155**	44,428	42,976
	2,540,909	3,017,353	4,353,538
OPERATING INCOME (LOSS)	**248,249**	(32,049)	221,723
OTHER INCOME (EXPENSE):			
Allowance for other funds used during construction	**5,765**	(36)	474
Interest accrued on deferred energy	**28,054**	23,058	55,204
Other income	**29,931**	10,988	12,450
Other expense	**(14,243)**	(18,373)	(13,634)
Income taxes	**(12,801)**	(4,058)	(14,870)
Unrealized loss on derivative instrument (Note 11)	**(46,065)**	—	—
	(9,359)	11,579	39,624
Total Income (Loss) Before Interest Charges	**238,890**	(20,470)	261,347

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

(continued)

CONSOLIDATED STATEMENTS OF OPERATIONS— SIERRA PACIFIC RESOURCES (continued)

Year ended December 31,	2003	2002	2001
(dollars in thousands, except per share amounts)			
INTEREST CHARGES:			
Long-term debt	**$ 295,458**	$ 250,173	$ 207,358
Other	**78,783**	35,478	23,892
Allowance for borrowed funds used during construction	**(5,976)**	(5,270)	(2,801)
	368,265	280,381	228,449
INCOME (LOSS) FROM CONTINUING OPERATIONS	**(129,375)**	(300,851)	32,898
DISCONTINUED OPERATIONS:			
Gain (loss) from discontinued operations (net of income taxes (benefits) of $(3,906), $(563), and $19,659 respectively)	**(7,254)**	(1,204)	27,535
CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE, net of tax (Note 1)	**—**	(1,566)	—
NET INCOME (LOSS)	**(136,629)**	(303,621)	60,433
Preferred stock dividend requirements of subsidiary	**3,900**	3,900	3,700
EARNINGS (LOSS) APPLICABLE TO COMMON STOCK	**$ (140,529)**	$ (307,521)	$ 56,733
Amount per share—basic and diluted			
Income/(loss) from continuing operations	**$ (1.12)**	$ (2.95)	$ 0.38
Income/(loss) per share applicable to common stock	**$ (1.21)**	$ (3.01)	$ 0.65
Weighted Average Shares of Common Stock Outstanding	**115,774,810**	102,126,079	87,542,441
Dividends Paid Per Share of Common Stock	**$ —**	$ 0.20	$ 0.65

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

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

Year ended December 31,	2003	2002	2001
(dollars in thousands)			
NET INCOME (LOSS)	**$(136,629)**	$(303,621)	$60,433
OTHER COMPREHENSIVE INCOME (LOSS)			
Adoption of SFAS No. 133—Accounting for Derivative Instruments and Hedging Activities:			
Cumulative effect upon adoption of change in accounting principle as of January 1 (net of income taxes of $1,035)	**—**	—	(1,923)
Change in market value of risk management assets and liabilities as of December 31 (net of income taxes (benefits) of $884, $3,083, and ($2,726) in 2003, 2002, and 2001, respectively)	**1,642**	5,726	(5,063)
Minimum pension liability adjustment (net of income taxes (benefits) of $8,698 and ($24,904) in 2003 and 2002, respectively)	**15,508**	(46,251)	—
OTHER COMPREHENSIVE INCOME (LOSS)	**17,150**	(40,525)	(6,986)
COMPREHENSIVE INCOME (LOSS)	**$(119,479)**	$(344,146)	$53,447

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

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY— SIERRA PACIFIC RESOURCES

Year ended December 31,	**2003**	2002	2001
(dollars in thousands)			
COMMON STOCK:			
Balance at Beginning of Year	**$ 102,177**	$ 102,111	$ 78,475
Stock issuance/exchange and dividend reinvestment	**15,059**	66	23,636
Balance at End of Year	**117,236**	102,177	102,111
OTHER PAID-IN CAPITAL:			
Balance at Beginning of Year	**1,599,024**	1,598,634	1,295,221
Premium on issuance/exchange of common stock	**99,192**	—	330,050
Common stock issuance costs	**(1,184)**	—	(13,910)
Purchase contract adjustment payment	**—**	—	(13,676)
Value of derivative transferred to equity	**118,143**	—	—
CSIP, DRP, ESPP, and other	**27**	390	949
Balance at End of Year	**1,815,202**	1,599,024	1,598,634
RETAINED EARNINGS (DEFICIT):			
Balance at Beginning of Year	**(326,524)**	1,577	(13,984)
Income (loss) from continuing operations before preferred dividends	**(129,375)**	(300,851)	32,898
Gain (loss) from discontinued operations (before preferred dividend allocation of $200 in 2001), net of taxes	**(7,254)**	(1,204)	27,735
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)	(41,172)
Balance at End of Year	**(466,683)**	(326,524)	1,577
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):			
Balance at Beginning of Year	**(47,511)**	(6,986)	—
Adoption of SFAS No. 133—Accounting for Derivative Instruments and Hedging Activities:			
Cumulative effect upon adoption of change in accounting principle as of January 1 (net of income taxes of $1,035)	**—**	—	(1,923)
Change in market value of risk management assets and liabilities as of December 31 (net of taxes (benefits) of $884, $3,083 and ($2,726) in 2003, 2002, and 2001, respectively)	**1,642**	5,726	(5,063)
Minimum pension liability adjustment (net of income taxes (benefits) of $8,698 and ($24,904) in 2003, and 2002, respectively)	**15,508**	(46,251)	—
Balance at End of Year	**(30,361)**	(47,511)	(6,986)
TOTAL COMMON SHAREHOLDERS' EQUITY AT END OF YEAR	**$1,435,394**	$1,327,166	$1,695,336

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

CONSOLIDATED STATEMENTS OF CASH FLOWS— SIERRA PACIFIC RESOURCES

Year ended December 31,	**2003**	2002	2001
(dollars in thousands)			
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net Income (Loss)	**$(136,629)**	$(303,621)	$ 60,433
Preferred dividends included in discontinued operations	**—**	—	200
Noncash items included in income (loss):			
Depreciation and amortization	**191,940**	175,218	169,289
Deferred taxes and deferred investment tax credit	**(50,724)**	(169,714)	85,917
AFUDC	**(11,741)**	(5,234)	(3,285)
Amortization of deferred energy costs—electric	**250,134**	176,718	—
Amortization of deferred energy costs—gas	**13,095**	13,231	3,562
Deferred energy costs disallowed	**90,964**	493,053	—
Early retirement and severance amortization	**2,786**	2,706	3,121
Unrealized loss on derivative instrument	**46,065**	—	—
Impairment of assets of subsidiary	**32,911**	—	—
Loss (gain) on disposal of discontinued operations	**9,555**	—	(44,082)
Other noncash	**(12,489)**	5,818	2,863
Adjustment in value of Premium Income Equity Securities	**—**	—	(13,677)
Changes in certain assets and liabilities:			
Accounts receivable	**57,357**	32,896	(887)
Deferral of energy costs—electric	**(179,826)**	(434,279)	(1,187,840)
Deferral of energy costs—gas	**2,592**	10,270	(30,245)
Materials, supplies, and fuel	**6,407**	6,448	(18,328)
Other current assets	**(49,781)**	(35,055)	4,454
Accounts payable	**(65,984)**	(29,307)	(97,340)
Income tax receivable	**—**	185,011	—
Other current liabilities	**358,057**	28,758	13,025
Change in net assets of discontinued operations	**—**	535	(10,893)
Other assets	**47,358**	(3,073)	(9,331)
Other liabilities	**(333,303)**	322,126	19,200
Net Cash from Operating Activities	**268,744**	472,505	(1,053,844)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to utility plant	**(373,961)**	(399,807)	(333,606)
AFUDC and other charges to utility plant	**11,741**	5,234	3,285
Customer advances for construction	**10,475**	7,852	815
Contributions in aid of construction	**23,605**	43,247	27,481
Net cash used for utility plant	**(328,140)**	(343,474)	(302,025)
Proceeds from sale of assets of water business	**—**	—	318,882
Investments in subsidiaries and other property—net	**(10,190)**	(59,077)	(9,065)
Net Cash from Investing Activities	**(338,330)**	(402,551)	7,792

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,	**2003**	2002	2001
(dollars in thousands)			
CASH FLOWS FROM FINANCING ACTIVITIES:			
Increase (decrease) in short-term borrowings	**$ 25,000**	$(177,000)	$ (36,074)
Restricted cash	**(41,000)**	(13,705)	—
Proceeds from issuance of long-term debt	**650,000**	350,000	1,225,503
Retirement of long-term debt	**(570,409)**	(112,269)	(323,091)
Redemption of preferred stock	**—**	—	(48,500)
Sale of common stock, net of issuance cost	**(756)**	460	340,737
Dividends paid	**(3,524)**	(24,485)	(64,917)
Net Cash from Financing Activities	**59,311**	23,001	1,093,658
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**(10,275)**	92,955	47,606
Beginning Balance in Cash and Cash Equivalents	**192,064**	99,109	51,503
Ending Balance in Cash and Cash Equivalents	**$ 181,789**	$ 192,064	$ 99,109
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION:			
Cash paid (received) during period for:			
Interest	**$ 307,870**	$ 257,462	$ 208,390
Income taxes	**$ (1,521)**	$(185,011)	$ (55,022)
NONCASH FINANCING ACTIVITIES (NOTE 8):			
Exchanged Floating Rate Notes for SPR common stock	**$ 8,750**	$ —	$ —
Exchanged 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,	2003	2002
(dollars in thousands, except per share data)		
COMMON SHAREHOLDERS' EQUITY:		
Common stock $1.00 par value, authorized 250 million; issued and outstanding 2003: 117,236,000 shares; 2002: 102,177,000 shares	**$ 117,236**	$ 102,177
Other paid-in capital	**1,815,202**	1,599,024
Retained earnings (deficit)	**(466,683)**	(326,524)
Accumulated other comprehensive loss	**(30,361)**	(47,511)
Total Common Shareholders' Equity	**1,435,394**	1,327,166
PREFERRED STOCK OF SUBSIDIARIES:		
Not subject to mandatory redemption		
Outstanding at December 31 Class A Series 1; $1.95 dividend	**50,000**	50,000
LONG-TERM DEBT:		
Unamortized bond premium and discount, net	**(21,750)**	(17,968)
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
Debt Secured by First Mortgage Bonds		
6.70% Series V due 2022	**105,000**	105,000
6.60% Series W due 2019	**39,500**	39,500
7.20% Series X due 2022	**78,000**	78,000
8.50% Series Z due 2023	**35,000**	35,000
6.35% Series FF due 2012	**1,000**	1,000
6.55% Series AA due 2013	**39,500**	39,500
6.30% Series DD due 2014	**45,000**	45,000
6.65% Series HH due 2017	**75,000**	75,000
6.65% Series BB due 2017	**17,500**	17,500
6.55% Series GG due 2020	**20,000**	20,000
6.30% Series EE due 2022	**10,250**	10,250
6.95% to 8.61% Series A MTN due 2022	**110,000**	110,000
7.10% and 7.14% Series B MTN due 2023	**58,000**	58,000
6.62% to 6.83% Series C MTN due 2006	**50,000**	50,000
5.90% Series JJ due 2023	**9,800**	9,800
5.90% Series KK due 2023	**30,000**	30,000
6.70% Series II due 2032	**21,200**	21,200
5.50% Series D MTN due 2003	**—**	5,000
5.59% Series D MTN due 2003	**—**	13,000
Subtotal, excluding current portion	**744,750**	762,750

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

(continued)

CONSOLIDATED STATEMENTS OF CAPITALIZATION— SIERRA PACIFIC RESOURCES (continued)

December 31,	2003	2002
(dollars in thousands, except per share data)		
Industrial Development Revenue Bonds		
5.90% Series 1997A due 2032	**$ 52,285**	$ 52,285
5.90% Series 1995B due 2030	**85,000**	85,000
5.60% Series 1995A due 2030	**76,750**	76,750
5.50% Series 1995C due 2030	**44,000**	44,000
Subtotal	**258,035**	258,035
Pollution Control Revenue Bonds		
6.38% due 2036	**20,000**	20,000
5.80% Series 1997B due 2032	**20,000**	20,000
5.30% Series 1995D due 2011	**14,000**	14,000
5.45% Series 1995D due 2023	**6,300**	6,300
5.35% Series 1995E due 2022	**13,000**	13,000
Subtotal	**73,300**	73,300
Variable Rate Notes		
Floating rate notes due 2003	**—**	140,000
IDRB Series 2000A due 2020	**100,000**	100,000
PCRB Series 2000B due 2009	**15,000**	15,000
Floating rate notes due 2003	**—**	200,000
Subtotal	**115,000**	455,000
Debt Secured by General and Refunding Bonds:		
8.25% Series A due 2011	**350,000**	350,000
10.88% Series E due 2009	**250,000**	250,000
9.00% Series G due 2019	**350,000**	—
8.00% Series A due 2008	**320,000**	320,000
10.50% (Variable) Series C due 2005	**99,000**	100,000
6.20% Series 1999B due 2004	**130,000**	130,000
Subtotal	**1,499,000**	1,150,000
Other Notes:		
7.50% Series 2001 due 2036	**80,000**	80,000
6.00% Series B notes due 2003	**—**	210,000
8.75% Senior unsecured note Series 2000 due 2005	**300,000**	300,000
7.93% Senior unsecured notes due 2007	**240,218**	—
7.25% Convertible notes due 2010	**234,118**	345,000
Subtotal	**854,336**	935,000
Obligations under capital leases	**68,587**	73,259
Current maturities and sinking fund requirements	**(238,636)**	(672,963)
Other	**32,339**	46,470
Total Long-Term Debt	**3,579,674**	3,257,596
TOTAL CAPITALIZATION	**$5,065,068**	$4,634,762

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

CONSOLIDATED BALANCE SHEETS—NEVADA POWER COMPANY

December 31,	2003	2002
(dollars in thousands)		
ASSETS		
Utility Plant at Original Cost:		
Plant-in-service	**$3,816,630**	$3,542,300
Less accumulated provision for depreciation	**1,018,044**	924,869
	2,798,586	2,617,431
Construction work-in-progress	**109,148**	173,189
	2,907,734	2,790,620
Investments and other property, net	**36,312**	26,136
Current Assets:		
Cash and cash equivalents	**144,897**	95,009
Restricted cash (Note 1)	**2,600**	3,850
Accounts receivable less allowance for uncollectible accounts: 2003—$40,297; 2002—$33,841	**167,296**	202,590
Accounts receivable, affiliate companies	**3,533**	—
Deferred energy costs—electric	**247,249**	213,193
Materials, supplies, and fuel, at average cost	**41,076**	44,074
Risk management assets (Note 11)	**11,702**	28,173
Deposits and prepayments for energy	**39,794**	12,347
Other	**21,540**	19,255
	679,687	618,491
Deferred Charges and Other Assets:		
Deferred energy costs—electric	**371,305**	524,345
Regulatory tax asset	**102,282**	106,071
Other regulatory assets	**60,721**	53,109
Risk management regulatory assets—net (Note 11)	**3,109**	1,491
Unamortized debt issuance expense	**34,052**	29,262
Other	**15,557**	17,463
	587,026	731,741
	$4,210,759	$4,166,988

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

(continued)

CONSOLIDATED BALANCE SHEETS—NEVADA POWER COMPANY (continued)

December 31,	**2003**	2002
(dollars in thousands)		
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Common shareholder's equity	**$1,174,645**	$1,149,131
Long-term debt	**1,899,709**	1,683,310
	3,074,354	2,832,441
Current Liabilities:		
Current maturities of long-term debt	**135,570**	354,677
Accounts payable	**107,812**	143,002
Accounts payable, affiliated companies	**—**	4,287
Accrued interest	**35,399**	25,791
Dividends declared	**78**	78
Accrued salaries and benefits	**10,315**	7,781
Deferred taxes	**107,459**	90,616
Risk management liabilities (Note 11)	**5,266**	29,908
Contract termination liabilities (Note 15)	**235,729**	—
Other current liabilities	**27,253**	22,115
	664,881	678,255
Commitments & Contingencies (Note 15)		
Deferred Credits and Other Liabilities:		
Deferred federal income taxes	**114,919**	129,687
Deferred investment tax credit	**20,272**	21,902
Regulatory tax liability	**15,776**	17,300
Customer advances for construction	**71,176**	66,434
Accrued retirement benefits	**5,825**	54,216
Contract termination liabilities (Note 15)	**43,916**	229,917
Regulatory liabilities (Note 1)	**147,887**	28,904
Accrued removal costs	**—**	92,625
Other	**51,753**	15,307
	471,524	656,292
	$4,210,759	$4,166,988

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

CONSOLIDATED STATEMENTS OF OPERATIONS— NEVADA POWER COMPANY

Year ended December 31,	2003	2002	2001
(dollars in thousands)			
OPERATING REVENUES:			
Electric	**$1,756,146**	$1,901,034	$3,025,103
OPERATING EXPENSES:			
Operation:			
Purchased power	**744,271**	1,241,783	3,026,336
Fuel for power generation	**319,711**	309,293	441,900
Deferred energy costs disallowed	**45,964**	434,123	—
Deferral of energy costs—net	**95,911**	(179,182)	(937,322)
Other	**195,483**	167,768	169,442
Maintenance	**48,226**	41,200	45,136
Depreciation and amortization	**109,655**	98,198	93,101
Taxes:			
Income taxes (benefits)	**(12,734)**	(133,411)	17,775
Other than income	**25,926**	25,265	24,371
	1,572,413	2,005,037	2,880,739
OPERATING INCOME (LOSS)	**183,733**	(104,003)	144,364
OTHER INCOME (EXPENSE):			
Allowance for other funds used during construction	**2,845**	(153)	(382)
Interest accrued on deferred energy	**22,891**	12,414	42,743
Other income	**18,344**	742	4,669
Other expense	**(5,944)**	(9,933)	(4,709)
Income taxes	**(12,120)**	(1,627)	(14,962)
	26,016	1,443	27,359
Total Income (Loss) Before Interest Charges	**209,749**	(102,560)	171,723
INTEREST CHARGES:			
Long-term debt	**142,143**	114,527	97,240
Other	**51,029**	21,395	13,219
Allowance for borrowed funds used during construction	**(2,700)**	(3,412)	(2,141)
	190,472	132,510	108,318
NET INCOME (LOSS)	**$ 19,277**	$ (235,070)	$ 63,405

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

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

Year ended December 31,	**2003**	2002	2001
(dollars in thousands)			
NET INCOME (LOSS)	**$19,277**	$(235,070)	$63,405
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX:			
Adoption of SFAS No. 133—Accounting for Derivative Instruments and Hedging Activities:			
Cumulative effect upon adoption of change in accounting principle as of January 1 (net of income taxes of $239)	**—**	—	444
Change in market value of risk management assets and liabilities as of December 31 (net of income taxes (benefits) of $31 and ($214) and $41 in 2003, 2002, and 2001, respectively)	**59**	(397)	76
Minimum pension liability adjustment (net of income taxes (benefits) of $3,326 and ($4,838) in 2003 and 2002, respectively)	**6,178**	(8,985)	—
OTHER COMPREHENSIVE INCOME (LOSS)	**6,237**	(9,382)	520
COMPREHENSIVE INCOME (LOSS)	**$25,514**	$(244,452)	$63,925

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

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDER'S EQUITY— NEVADA POWER COMPANY

Year ended December 31,	**2003**	2002	2001
(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**	1,367,106	892,185
Additional investment by parent company	**—**	10,000	474,921
Balance at End of Year	**1,377,106**	1,377,106	1,367,106
RETAINED EARNINGS (DEFICIT):			
Balance at Beginning of Year	**(219,114)**	25,956	(4,449)
Income (loss) for the year	**19,277**	(235,070)	63,405
Common stock dividends declared	**—**	(10,000)	(33,000)
Balance at End of Year	**(199,837)**	(219,114)	25,956
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):			
Balance at Beginning of Year	**(8,862)**	520	—
Adoption of SFAS No. 133—Accounting for Derivative Instruments and Hedging Activities:			
Cumulative effect upon adoption of change in accounting principle as of January 1 (net of income taxes of $239)	**—**	—	444
Change in market value of risk management assets and liabilities as of December 31 (net of income taxes (benefit) of $31, ($214), and $41 in 2003, 2002, and 2001, respectively)	**59**	(397)	76
Minimum pension liability adjustment (net of income taxes (benefit) of $3,326 and ($4,838) in 2003 and 2002, respectively)	**6,178**	(8,985)	—
Balance at End of Year	**(2,625)**	(8,862)	520
TOTAL COMMON SHAREHOLDER'S EQUITY AT END OF YEAR	**$1,174,645**	$1,149,131	$1,393,583

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

CONSOLIDATED STATEMENTS OF CASH FLOWS—NEVADA POWER COMPANY

Year ended December 31,	2003	2002	2001
(dollars in thousands)			
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	**$ 19,277**	$(235,070)	$ 63,405
Noncash items included in income (loss):			
Depreciation and amortization	**109,655**	98,198	93,102
Deferred taxes and deferred investment tax credit	**2,710**	(131,076)	55,085
AFUDC	**(5,545)**	(3,259)	(1,759)
Amortization of deferred energy costs	**204,610**	146,554	—
Deferred energy costs disallowed	**45,964**	434,125	—
Other noncash	**(11,264)**	(8,818)	264
Changes in certain assets and liabilities:			
Accounts receivable	**31,761**	8,487	(41,444)
Deferral of energy costs	**(131,590)**	(338,152)	(980,065)
Materials, supplies and fuel	**2,998**	4,437	(2,938)
Other current assets	**(29,732)**	(24,841)	3,507
Accounts payable	**(39,477)**	(55,316)	44,747
Income tax receivable	**—**	102,904	—
Other current liabilities	**253,009**	6,216	3,812
Other assets	**21,303**	—	—
Other liabilities	**(208,051)**	253,218	4,882
Net Cash from Operating Activities	**265,628**	257,607	(757,402)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to utility plant	**(227,066)**	(294,480)	(200,852)
AFUDC and other charges to utility plant	**5,545**	3,259	1,759
Customer advances (refunds) for construction	**4,742**	4,980	(4,134)
Contributions in aid of construction	**12,168**	35,800	6,331
Net cash used for utility plant	**(204,611)**	(250,441)	(196,896)
Investments in subsidiaries and other property—net	**(15,512)**	(2,239)	(115)
Net Cash from Investing Activities	**(220,123)**	(252,680)	(197,011)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Increase (decrease) in short-term borrowings	**—**	(130,500)	30,500
Restricted cash	**1,250**	(3,850)	—
Proceeds from issuance of long-term debt	**350,000**	250,000	815,000
Retirement of long-term debt	**(346,867)**	(34,073)	(368,347)
Investment by parent company	**—**	10,000	474,921
Dividends paid	**—**	(10,000)	(33,014)
Net Cash from Financing Activities	**4,383**	81,577	919,060
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**49,888**	86,504	(35,353)
Beginning Balance in Cash and Cash Equivalents	**95,009**	8,505	43,858
Ending Balance in Cash and Cash Equivalents	**$ 144,897**	$ 95,009	$ 8,505
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION:			
Cash paid (received) during period for:			
Interest	**$ 149,686**	$ 109,679	$ 90,280
Income taxes	**$ —**	$(102,904)	$ (13,702)

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

CONSOLIDATED STATEMENTS OF CAPITALIZATION— NEVADA POWER COMPANY

December 31,	2003	2002
(dollars in thousands, except per share data)		
COMMON SHAREHOLDER'S EQUITY:		
Common stock issued, stated value $1, 1,000 shares authorized, issued and outstanding	**$ 1**	$ 1
Other paid-in capital	**1,377,106**	1,377,106
Accumulated deficit	**(199,837)**	(219,114)
Accumulated Other Comprehensive Loss	**(2,625)**	(8,862)
Total Common Shareholder's Equity	**1,174,645**	1,149,131
LONG-TERM DEBT:		
Unamortized bond premium and discount, net	**(11,929)**	(13,906)
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
Total Preferred Securities	**194,713**	194,713
Debt Secured by First Mortgage Bonds:		
6.70% Series V due 2022	**105,000**	105,000
6.60% Series W due 2019	**39,500**	39,500
7.20% Series X due 2022	**78,000**	78,000
8.50% Series Z due 2023	**35,000**	35,000
Subtotal	**257,500**	257,500
Industrial development revenue bonds		
5.90% Series 1997A due 2032	**52,285**	52,285
5.90% Series 1995B due 2030	**85,000**	85,000
5.60% Series 1995A due 2030	**76,750**	76,750
5.50% Series 1995C due 2030	**44,000**	44,000
Subtotal	**258,035**	258,035
Pollution Control Revenue Bonds		
6.38% Series 1996 due 2036	**20,000**	20,000
5.80% Series 1997B due 2032	**20,000**	20,000
5.30% Series 1995D due 2011	**14,000**	14,000
5.45% Series 1995D due 2023	**6,300**	6,300
5.35% Series 1995E due 2022	**13,000**	13,000
Subtotal	**73,300**	73,300
Variable Rate Notes		
Floating rate notes due 2003	**—**	140,000
IDRB Series 2000A due 2020	**100,000**	100,000
PCRB Series 2000B due 2009	**15,000**	15,000
Subtotal	**115,000**	255,000
Debt Secured by General and Refunding Bonds:		
8.25% Series A due 2011	**350,000**	350,000
10.88% Series E due 2009	**250,000**	250,000
9.00% Series G due 2019	**350,000**	—
6.20% Series 1999B due 2004	**130,000**	130,000
Subtotal	**1,080,000**	730,000
Other Notes:		
6.0% Series B notes due 2003	**—**	210,000
Obligation under capital leases	**68,587**	73,259
Current maturities and sinking fund requirements	**(135,570)**	(354,677)
Other, excluding current portion	**73**	86
Total Long-Term Debt	**1,899,709**	1,683,310
TOTAL CAPITALIZATION	**$3,074,354**	$2,832,441

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

CONSOLIDATED BALANCE SHEETS— SIERRA PACIFIC POWER COMPANY

December 31,	2003	2002
(dollars in thousands)		
ASSETS		
Utility Plant at Original Cost:		
Plant-in-service	**$2,536,769**	$2,447,401
Less accumulated provision for depreciation	**935,227**	867,831
	1,601,542	1,579,570
Construction work-in-progress	**133,374**	90,157
	1,734,916	1,669,727
Investments and other property, net	**916**	874
Current Assets:		
Cash and cash equivalents	**20,859**	88,910
Restricted cash (Note 1)	**8,776**	9,605
Accounts receivable less allowance for uncollectible accounts: 2003—$4,620; 2002—$10,343	**133,595**	154,821
Accounts receivable, affiliated companies	**56,349**	58,680
Deferred energy costs—electric	**48,428**	55,786
Deferred energy costs—gas	**1,358**	17,045
Materials, supplies and fuel, at average cost	**38,449**	41,727
Risk management assets (Note 11)	**10,397**	1,397
Deposits and prepayments for energy	**24,053**	4,847
Other	**7,265**	8,108
	349,529	440,926
Deferred Charges and Other Assets:		
Deferred energy costs—electric	**126,600**	161,530
Regulatory tax asset	**53,265**	57,818
Other regulatory assets	**62,716**	64,149
Risk management regulatory assets—net (Note 11)	**11,174**	43,479
Unamortized debt issuance expense	**12,383**	13,138
Other	**10,970**	5,875
	277,108	345,989
	$2,362,469	$2,457,516

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

(continued)

CONSOLIDATED BALANCE SHEETS— SIERRA PACIFIC POWER COMPANY (continued)

December 31,	**2003**	2002
(dollars in thousands)		
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Common shareholder's equity	**$ 593,771**	$ 639,295
Preferred stock	**50,000**	50,000
Long-term debt	**912,800**	914,788
	1,556,571	1,604,083
Current Liabilities:		
Short-term borrowings	**25,000**	—
Current maturities of long-term debt	**83,400**	101,400
Accounts payable	**40,731**	71,247
Accrued interest	**10,374**	10,673
Dividends declared	**968**	968
Accrued salaries and benefits	**11,775**	10,812
Deferred taxes	**26,385**	32,891
Risk management liabilities (Note 11)	**11,274**	40,045
Contract termination liabilities (Note 15)	**102,975**	—
Other current liabilities	**7,129**	10,864
	320,011	278,900
Commitments & Contingencies (Note 15)		
Deferred Credits and Other Liabilities:		
Deferred federal income taxes	**230,615**	251,487
Deferred investment tax credit	**25,057**	26,590
Regulatory tax liability	**26,101**	25,418
Customer advances for construction	**55,330**	49,598
Accrued retirement benefits	**52,709**	44,856
Risk management liabilities (Note 11)	**—**	3,917
Contract termination liabilities (Note 15)	**1,850**	88,241
Regulatory liabilities	**70,271**	—
Accrued removal costs	**—**	59,026
Other	**23,954**	25,400
	485,887	574,533
	$2,362,469	$2,457,516

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

CONSOLIDATED STATEMENTS OF OPERATIONS— SIERRA PACIFIC POWER COMPANY

Year ended December 31,	2003	2002	2001
(dollars in thousands)			
OPERATING REVENUES:			
Electric	**$ 868,280**	$ 931,251	$1,401,778
Gas	**161,586**	149,783	145,652
	1,029,866	1,081,034	1,547,430
OPERATING EXPENSES:			
Operation:			
Purchased power	**360,073**	545,040	1,025,741
Fuel for power generation	**201,701**	144,143	286,719
Gas purchased for resale	**111,675**	91,961	136,534
Deferred energy costs disallowed	**45,000**	56,958	—
Deferral of energy costs—electric—net	**1,982**	(54,632)	(198,826)
Deferral of energy costs—gas—net	**16,155**	24,785	(23,170)
Other	**116,390**	106,122	118,526
Maintenance	**21,410**	23,240	24,363
Depreciation and amortization	**81,514**	76,373	72,103
Taxes:			
Income taxes	**(13,704)**	(6,922)	8,507
Other than income	**19,104**	18,674	17,965
	961,300	1,025,742	1,468,462
OPERATING INCOME	**68,566**	55,292	78,968
OTHER INCOME (EXPENSE):			
Allowance for other funds used during construction	**2,920**	117	856
Interest accrued on deferred energy	**5,163**	10,644	12,461
Other income	**4,403**	4,266	2,113
Other expense	**(6,767)**	(6,577)	(6,176)
Income taxes	**(1,467)**	(2,431)	91
	4,252	6,019	9,345
Total Income Before Interest Charges	**72,818**	61,311	88,313
INTEREST CHARGES:			
Long-term debt	**76,002**	66,474	58,797
Other	**23,367**	10,663	7,433
Allowance for borrowed funds used during construction and capitalized interest	**(3,276)**	(1,858)	(660)
	96,093	75,279	65,570
INCOME (LOSS) FROM CONTINUING OPERATIONS	**(23,275)**	(13,968)	22,743
DISCONTINUED OPERATIONS:			
Gain from discontinued operations (net of income taxes of $19,125)	**—**	—	26,867
NET INCOME (LOSS)	**(23,275)**	(13,968)	49,610
Preferred Dividend Requirements	**3,900**	3,900	3,700
Earnings (loss) applicable to common stock	**$ (27,175)**	$ (17,868)	$ 45,910

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,	**2003**	2002	2001
(dollars in thousands)			
NET INCOME (LOSS)	**$(23,275)**	$(13,968)	$49,610
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX:			
Cumulative effect upon adoption of change in accounting principle as of January 1 (net of income taxes of $114)	**—**	—	211
Change in market value of risk management assets and liabilities as of December 31 (net of income taxes (benefits) of $15, ($102), and $19 in 2003, 2002, and 2001, respectively)	**28**	(189)	36
Minimum pension liability adjustment (net of income taxes (benefits) of $83 and ($349) in 2003 and 2002, respectively)	**153**	(649)	—
OTHER COMPREHENSIVE INCOME (LOSS)	**181**	(838)	247
COMPREHENSIVE INCOME (LOSS)	**$(23,094)**	$(14,806)	$49,857

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

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDER'S EQUITY— SIERRA PACIFIC POWER COMPANY

Year ended December 31,	**2003**	2002	2001
(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**	703,633	598,684
Additional investment by parent company	**—**	10,000	104,949
Balance at End of Year	**713,633**	713,633	703,633
RETAINED EARNINGS (DEFICIT):			
Balance at Beginning of Year	**(73,751)**	(10,983)	6,107
Income (Loss) from continuing operations before preferred dividends	**(23,275)**	(13,968)	22,743
Gain from discontinued operations (before preferred dividend allocation of $200), net of taxes	**—**	—	27,067
Preferred stock dividends declared	**(3,900)**	(3,900)	(3,900)
Common stock dividends declared	**(18,530)**	(44,900)	(63,000)
Balance at End of Year	**(119,456)**	(73,751)	(10,983)
ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS):			
Balance at Beginning of Year	**(591)**	247	—
Adoption of SFAS No. 133—Accounting for Derivative Instruments and Hedging Activities:			
Cumulative effect upon adoption of change in accounting principle as of January 1 (net of income taxes of $114)	**—**	—	211
Change in market value of risk management assets and liabilities as of December 31 (net income of taxes (benefits) of $15, ($102), and $19 in 2003, 2002, and 2001, respectively)	**28**	(189)	36
Minimum pension liability adjustment (net of income taxes (benefits) of $83 and ($349) in 2003 and 2002, respectively)	**153**	(649)	—
Balance at End of Year	**(410)**	(591)	247
TOTAL COMMON SHAREHOLDER'S EQUITY AT END OF YEAR	**$ 593,771**	$639,295	$692,901

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

CONSOLIDATED STATEMENTS OF CASH FLOWS— SIERRA PACIFIC POWER COMPANY

Year ended December 31,	2003	2002	2001
(dollars in thousands)			
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	**$ (23,275)**	$ (13,968)	$ 49,610
Preferred dividends included in discontinued operations	**—**	—	200
Noncash items included in income (loss):			
Depreciation and amortization	**81,514**	76,373	75,584
Deferred taxes and deferred investment tax credit	**(23,676)**	(5,107)	57,382
AFUDC	**(6,196)**	(1,975)	(1,526)
Amortization of deferred energy costs—electric	**45,524**	30,164	—
Amortization of deferred energy costs—gas	**13,095**	13,231	3,562
Deferred energy costs disallowed	**45,000**	58,928	—
Early retirement and severance amortization	**2,786**	2,706	3,121
Gain on disposal of water business	**—**	—	(44,082)
Other noncash	**(8,259)**	(6,130)	(299)
Changes in certain assets and liabilities:			
Accounts receivable	**23,557**	(18,803)	(36,835)
Deferral of energy costs—electric	**(48,236)**	(96,127)	(207,775)
Deferral of energy costs—gas	**2,592**	10,270	(30,245)
Materials, supplies and fuel	**3,278**	880	(12,700)
Other current assets	**(18,363)**	(7,020)	1,836
Accounts payable	**(30,516)**	(24,308)	(70,579)
Income tax receivable	**—**	62,109	—
Other current liabilities	**99,904**	5,088	2,380
Other assets	**26,055**	(856)	—
Other liabilities	**(112,673)**	88,145	(1,333)
Net Cash from Operating Activities	**72,111**	173,600	(211,699)
CASH FLOWS FROM INVESTING ACTIVITIES:			
Additions to utility plant	**(146,895)**	(105,327)	(132,754)
AFUDC and other charges to utility plant	**6,196**	1,975	1,526
Customer advances for construction	**5,733**	2,872	4,949
Contributions in aid of construction	**11,437**	7,447	21,150
Net cash used for utility plant	**(123,529)**	(93,033)	(105,129)
Proceeds from sale of assets of water business	**—**	—	318,882
Disposal of subsidiaries and other property—net	**(43)**	993	17
Net Cash from Investing Activities	**(123,572)**	(92,040)	213,770
CASH FLOWS FROM FINANCING ACTIVITIES:			
Increase (decrease) in short-term borrowings	**25,000**	(46,500)	(62,462)
Restricted cash	**829**	(9,605)	—
Proceeds from issuance of long-term debt	**—**	100,000	400,000
Retirement of long-term debt	**(19,989)**	(9,512)	(299,732)
Redemption of preferred stock	**—**	—	(48,500)
Investment by parent company	**—**	10,000	104,948
Dividends paid	**(22,430)**	(48,805)	(89,901)
Net Cash from Financing Activities	**(16,590)**	(4,422)	4,353
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**(68,051)**	77,138	6,424
Beginning Balance in Cash and Cash Equivalents	**88,910**	11,772	5,348
Ending Balance in Cash and Cash Equivalents	**$ 20,859**	$ 88,910	$ 11,772
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION:			
Cash paid (received) during period for:			
Interest	**$ 85,088**	$ 73,409	$ 66,597
Income taxes	**$ (1,521)**	$ (62,109)	$ (25,632)

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

CONSOLIDATED STATEMENTS OF CAPITALIZATION— SIERRA PACIFIC POWER COMPANY

December 31,	2003	2002
(dollars in thousands, except per share data)		
COMMON SHAREHOLDER'S EQUITY:		
Common stock, $3.75 par value, 1,000 shares authorized, issued and outstanding	**$ 4**	$ 4
Other paid-in capital	**713,633**	713,633
Deficit	**(119,456)**	(73,751)
Accumulated Other Comprehensive Income	**(410)**	(591)
Total Common Shareholder's Equity	**593,771**	639,295
CUMULATIVE PREFERRED STOCK:		
Not subject to mandatory redemption $25 stated value		
Class A Series 1; $1.95 dividend	**50,000**	50,000
LONG-TERM DEBT:		
Unamortized bond premium and discount, net	**(2,650)**	(4,062)
Debt Secured by First Mortgage Bonds		
6.35% Series FF due 2012	**1,000**	1,000
6.55% Series AA due 2013	**39,500**	39,500
6.30% Series DD due 2014	**45,000**	45,000
6.65% Series HH due 2017	**75,000**	75,000
6.65% Series BB due 2017	**17,500**	17,500
6.55% Series GG due 2020	**20,000**	20,000
6.30% Series EE due 2022	**10,250**	10,250
6.95% to 8.61% Series A MTN due 2022	**110,000**	110,000
7.10% and 7.14% Series B MTN due 2023	**58,000**	58,000
6.62% to 6.83% Series C MTN due 2006	**50,000**	50,000
5.90% Series JJ due 2023	**9,800**	9,800
5.90% Series KK due 2023	**30,000**	30,000
6.70% Series II due 2032	**21,200**	21,200
5.50% Series D MTN due 2003	**—**	5,000
5.59% Series D MTN due 2003	**—**	13,000
Subtotal	**487,250**	505,250
Debt Secured by General and Refunding Bonds		
8.00% Series A due 2008	**320,000**	320,000
10.50% (Variable) Series C due 2005	**99,000**	100,000
	419,000	420,000
Other Notes:		
7.50% Series 2001 due 2036	**80,000**	80,000
Other	**12,600**	15,000
Current maturities and sinking fund requirements	**(83,400)**	(101,400)
Total Long-Term Debt	**912,800**	914,788
TOTAL CAPITALIZATION	**$1,556,571**	$1,604,083

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). e·three is a discontinued operation and as such is 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 60% of the consolidated assets of SPR at December 31, 2003. NPC provides electricity to approximately 703,000 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 NPC 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 33% of the consolidated assets of SPR at December 31, 2003. SPPC provides electricity to approximately 334,000 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 129,000 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.

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.

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.

Management periodically assesses whether the requirements for application of SFAS No. 71 are satisfied. The provisions of Assembly Bill 369 (AB 369), signed into law in April 2001, include the repeal of all statutes authorizing retail competition in Nevada's electric utility industry. Accordingly, the Utilities continue to apply regulatory accounting to the generation, transmission, and distribution portions of their businesses.

The following Other regulatory assets were included in the consolidated balance sheets of SPR as of December 31 (dollars in thousands):

SIERRA PACIFIC RESOURCES

Other Regulatory Assets and Liabilities

DESCRIPTION	Remaining Amortization Period	Receiving Regulatory Treatment: Earning a Return[1][2]	Receiving Regulatory Treatment: Not Earning a Return	Pending Regulatory Treatment	**2003 Total**	2002 Total
Regulatory Assets						
Early retirement and severance offers	Various through 2004	$ —	$2,497	$ —	**$ 2,497**	$ 4,995
Loss on reacquired debt	Various	30,123	—	—	**30,123**	31,812
Plant assets	Various through 2031	3,414	—	—	**3,414**	3,558
Nevada divestiture costs		—	—	35,164[2]	**35,164**	32,313
Merger transition costs		—	—	14,185	**14,185**	12,601
Merger severance/relocation		—	—	21,375	**21,375**	21,747
Merger goodwill		—	—	19,070	**19,070**	19,675
California restructure costs	Through 2008	2,448	—	1,920	**4,368**	4,318
Conservation programs		—	—	8,361	**8,361**	3,374
Variable rate mechanism deferral	Through 10/04	—	352	—	**352**	721
Other costs		—	—	3,598	**3,598**	1,819
Total other regulatory assets		$ 35,985	$2,849	$103,673	**$142,507**	$136,933
Regulatory Liabilities						
Cost of removal		$174,717	$ —	$ —	**$174,717**	$ —
Gain on property sales	Various through 2006	16,430	900	21,982	**39,312**	2,341
SO2 allowances	Various through 2006	4,129	—	—	**4,129**	7,313
Deferred fuel over-collection		—	—	—	—	19,250
Total Regulatory Liabilities		$195,276	$ 900	$ 21,982	**$218,158**	$ 28,904

NOTES TO FINANCIAL STATEMENTS (continued)

NEVADA POWER COMPANY

Other Regulatory Assets and Liabilities

DESCRIPTION	Remaining Amortization Period	Receiving Regulatory Treatment: Earning a Return(1)(2)	Receiving Regulatory Treatment: Not Earning a Return	Pending Regulatory Treatment	**2003 Total**	2002 Total
Loss on reacquired debt	Various	$ 13,956	$ —	$ —	**$ 13,956**	$14,778
Nevada divestiture costs		—	—	21,886(2)	**21,886**	20,134
Merger transition costs		—	—	7,652	**7,652**	5,328
Merger severance/relocation		—	—	10,209	**10,209**	10,199
Conservation programs		—	—	6,809	**6,809**	2,478
Other costs		—	—	209	**209**	192
Total Other Regulatory Assets		$ 13,956	$ —	$46,765	**$ 60,721**	$53,109
Regulatory Liabilities						
Cost of removal		$104,446	$ —	$ —	**$104,446**	$ —
Gain on property sales	Various through 2006	16,430	900	21,982	**39,312**	2,341
SO2 allowances	Various through 2006	4,129	—	—	**4,129**	7,313
Deferred fuel over-collection		—	—	—	—	19,250
Total Regulatory Liabilities		$125,005	$900	$21,982	**$147,887**	$28,904

SIERRA PACIFIC POWER COMPANY

Other Regulatory Assets and Liabilities

DESCRIPTION	Remaining Amortization Period	Receiving Regulatory Treatment: Earning a Return(1)(2)	Receiving Regulatory Treatment: Not Earning a Return	Pending Regulatory Treatment	**2003 Total**	2002 Total
Early retirement and severance offers	Various through 2004	$ —	$2,497	$ —	**$ 2,497**	$ 4,995
Loss on reacquired debt	Various	16,167	—	—	**16,167**	17,034
Plant assets	Various through 2031	3,414	—	—	**3,414**	3,558
Nevada divestiture costs		—	—	13,278(2)	**13,278**	12,179
Merger transition costs		—	—	6,533	**6,533**	7,273
Merger severance/relocation		—	—	11,166	**11,166**	11,548
California restructure costs	Through 2008	2,448	—	1,920	**4,368**	4,318
Conservation programs	Various through 2007	—	—	1,552	**1,552**	896
Variable rate mechanism deferral	Through 10/04	—	352	—	**352**	721
Other costs		—	—	3,389	**3,389**	1,627
Total other Regulatory Assets		$22,029	$2,849	$37,838	**$62,716**	$64,149
Regulatory Liabilities						
Cost of removal		$70,271	$ —	$ —	**$70,271**	$ —

(1) Regulatory liabilities included in this column are treated as reductions to rate base, on which a rate of return is earned.

(2) Regulatory asset is currently earning a return.

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.

AB 369 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, AB 369 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, 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**
Balances accrued since end of periods submitted for PUCN approval(1)	**8,477**	**3,559**	**417**	**12,453**
Terminated supply contracts(2)	**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**
Total	**$618,554**	**$175,028**	**$1,358**	**$794,940**

	December 31, 2002			
DESCRIPTION	NPC Electric	SPPC Electric	SPPC Gas	SPR Total
Unamortized balances approved for collection in current rates	$331,159	$120,183	$18,957	$470,299
Balances pending PUCN approval	195,670	15,380	—	211,050
Balances accrued since end of periods submitted for PUCN approval(1)	(17,750)	(148)	(1,912)	(19,810)
Terminated supply contracts(2)	228,459	81,901	—	310,360
Total	$737,538	$217,316	$17,045	$971,899
Current Assets				
Deferred energy costs—electric	$213,193	$ 55,786	$ —	$268,979
Deferred energy costs—gas	—	—	17,045	17,045
Deferred Assets				
Deferred energy costs—electric	524,345	161,530	—	685,875
Total	$737,538	$217,316	$17,045	$971,899

(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) Amounts related to claims for terminated supply contracts are discussed in Note 15, of Notes to Financial Statements, Commitments and Contingencies.

NOTES TO FINANCIAL STATEMENTS (continued)

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, postretirement and postemployment 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 2003, 2002, and 2001 were 8.37%, 4.72%, and 8.32%, respectively. SPPC's AFUDC rates used during 2003, 2002, and 2001 were 8.61%, 5.54%, and 7.97%, respectively. As specified by the PUCN, certain projects were 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 2003, 2002, and 2001, as authorized by the PUCN and stated as a percentage of the original cost of depreciable property, was approximately 3.06%, 3.0%, and 2.94%, respectively. SPPC's depreciation provision for 2003, 2002, and 2001, as authorized by the PUCN and stated as a percentage of the original cost of depreciable property, was approximately 3.31%, 3.33%, and 3.29%, 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." See Note 19 of Notes to Financial Statements, 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.

SPR's Consolidated Balance Sheet as of December 31, 2003, includes approximately $325 million of goodwill pertaining to regulated operations resulting from the July 28, 1999 merger between SPR and NPC. The PUCN stipulation approving the merger allows for future recovery of this goodwill in rates charged to customers of SPR's regulated utility subsidiaries, NPC and SPPC, provided that NPC and SPPC demonstrate that merger savings exceed merger costs. The amount and timing of the recovery of this goodwill will be determined by the outcome of general rate cases filed by NPC and SPPC on October 1, 2003 and December 1, 2003, respectively. The decisions on these cases are expected in the spring of 2004. For further discussion, see Note 15, of Notes to Financial Statements, Commitments and Contingencies, Regulatory.

On January 1, 2003, SPR reviewed goodwill of the unregulated subsidiaries for impairment. As of January 1, 2003, SPR recorded an additional $470,000 to operating expense for impairment of goodwill. As of December 31, 2003, goodwill related to the unregulated subsidiaries, included in SPR's Consolidated Balance Sheet, is approximately $4.0 million.

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, 2003 and 2002, SPR had approximately $55 million and $14 million, respectively of restricted cash in SPR's consolidated balance sheets, primarily all of which is restricted for debt service payments for the $300 million convertible notes, discussed in Note 8, Long-Term Debt and 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 and Investment Tax Credits

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 basics of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse.

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, 2003, include unbilled receivables of $63 million and $56 million for NPC and SPPC, respectively. Accounts receivable as of December 31, 2002, include unbilled receivables of $60 million and $63 million for NPC and SPPC, respectively. Accounts receivable, affiliate companies is comprised mainly of amounts owed as a result of tax sharing agreements.

Stock Compensation Plans

At December 31, 2003, SPR had several stock-based compensation plans, which are described more fully in Note 14 of Notes to Financial Statements, 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. 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 below (dollars in thousands, except per share amounts):

		2003	2002	2001
Earnings (loss) applicable to common stock, as reported		**$(140,529)**	$(307,521)	$56,733
Add: Stock (loss) compensation cost included in net income as reported, net of related tax effects		**410**	(1,567)	346
Less: Pro forma stock compensation cost, net of related tax effects		**(1,750)**	(480)	(1,555)
Pro forma earnings (loss) applicable to common stock		**$(141,869)**	$(309,568)	$55,524
Basic earnings (loss) per share	As Reported	**$ (1.21)**	$ (3.01)	$ 0.65
	Pro Forma	**$ (1.22)**	$ (3.03)	$ 0.63
Diluted earnings (loss) per share	As Reported	**$ (1.21)**	$ (3.01)	$ 0.65
	Pro Forma	**$ (1.22)**	$ (3.03)	$ 0.63

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 will be recognized at fair value as incurred and capitalized as part of the cost of the related tangible long-lived assets. Accretion of the liabilities due to the passage of time will be an operating expense. 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.

NOTES TO FINANCIAL STATEMENTS (continued)

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.

Management operates the transmission and distribution system as though they will be operated in perpetuity and will continue to be used or sold without land remediation.

In addition to the asset retirement obligations the Utilities have accrued for the cost of removing other electric and gas assets through its depreciation rates, in accordance with accepted regulatory practices. The accrual was previously included in accumulated depreciation but is currently reflected as regulatory liabilities, as of December 31, 2003 and as accrued cost of removal as of December 31, 2002. The amount of such accruals included in regulatory liabilities in 2003 of approximately $104 million and $70 million for NPC and SPPC, respectively. Approximately $92 million and $59 million for NPC and SPPC respectively, based on the cost of removal component in current depreciation rates.

Recent Pronouncements

In December 2003, the FASB issued Interpretation No. 46, 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, we have adopted FIN 46(R) for special purpose entities. Management believes that NPC's Trust I and Trust III subsidiaries (Preferred Trust Securities) are variable interest entities but management believes that NPC is not the primary beneficiary, as such, under the provisions of FIN 46(R), NPC is required to deconsolidate. FIN 46(R) encourages restatement of prior periods, as such all periods presented have been restated to reflect the deconsolidation of NPC's Preferred Trust Securities. As a result, the Preferred Trust Securities previously reported in Long-Term Debt upon consolidation, are no longer reported and NPC's Junior Subordinated Debt, which was previously eliminated upon consolidation, is now reported as Long-Term Debt. Additionally, the $5.8 million equity investment NPC had in the Trusts is recorded as Investments in Subsidiaries and Other Property and Long-Term Debt for all periods presented. The $5.8 million represents NPC's maximum exposure to loss as a result of its involvement with the variable interest entity. The deconsolidation did not have an effect on the results of operations for SPR or NPC, except that Dividend requirements of NPC's Obligated Mandatorily Redeemable Preferred Trust Securities have been reclassified to Interest Charges—Long-Term Debt for all periods presented. See Note 8 of Notes to Financial Statements, Long-Term Debt for a description of the Preferred Trust Securities.

Management has identified certain relationships such as, joint and shared facilities and agreements with other power suppliers, that we may have a variable interest in or be the primary beneficiary for which the provisions of FIN 46(R) would apply. At this time management is unable to determine if (1) we will be required to consolidate the various entities, or (2) the financial impact on SPR's, NPC's, or SPPC's financial position, or results of operations will be material. FIN 46(R) requires that SPR, NPC, and SPPC apply this interpretation to all entities subject to this interpretation by March 31, 2004.

On April 30, 2003, the FASB issued SFAS No. 149 "Amendment of Statement 133 on Derivative Instruments and Hedging Activities," which amends accounting for derivative instruments, including certain derivative instruments embedded in other contracts, and hedging activities under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." The Statement clarifies the circumstances under which a contract with an initial net investment meets the characteristics of a derivative as discussed in SFAS No. 133. In addition, SFAS No. 149 clarifies when a derivative contains a financing component that warrants special reporting in the statement of cash flows. SFAS No. 149 is effective for contracts entered into or modified after June 30, 2003, and for hedging relationships designated after June 30, 2003. The adoption of SFAS No. 149 has had no effect on the financial position, results of operation, or cash flows of SPR, NPC, or SPPC.

On May 15, 2003, the FASB issued SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of Liabilities and Equity," which requires that certain financial instruments with characteristics of both liabilities and equities be classified as liabilities by their issuers. The provisions of SFAS No. 150, which also include a number of new disclosure requirements, are effective for (1) instruments entered into or modified after May 31, 2003 and (2) pre-existing instruments as of the beginning of the first interim period that commences after June 15, 2003. At December 31, 2003, the adoption of SFAS No. 150 did not have an effect on the financial position, results of operations, or cash flows for SPR, NPC, and SPPC.

In December 2003, the FASB revised SFAS No. 132 "Employers' Disclosures about Pensions and Other Postretirement Benefits," which revises employers' disclosures about pension plans and other postretirement benefit plans. It does not change the measurement or recognition of those plans required by SFAS No. 87, "Employers' Accounting for Pensions," SFAS No. 88, "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits," and SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions." This statement requires additional disclosures about the assets, obligations, cash flows, and net periodic benefit cost of defined benefit pension plans and other defined benefit postretirement plans. SPR, NPC, and SPPC adopted the revised standard as of December 31, 2003. See Note 13 of Notes to Financial Statements, Retirement Plan, and Postretirement Benefits.

In December 2003, the FASB issued FASB Staff Position No. 106-1 (FSP No. 106-1), in response to the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act) signed into law in December 2003. The Act introduces a prescription drug benefit under Medicare (Medicare Part D) as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. Paragraph 40 of SFAS No. 106, "Employers Accounting for Postretirement Benefits Other Than Pensions," requires presently enacted changes in relevant laws to be considered in current period measurements of postretirement benefit costs and the Accumulated Pension Benefit Obligation (APBO). Therefore, under that guidance, measures of the APBO and net periodic postretirement benefit costs on or after the date of enactment should reflect the effects of the Act. However, due to several uncertainties of the Act, under FSP No. 106-1 SPR is permitted to defer recognizing the effects of the Act in the accounting for its plan under Statement 106 and in providing disclosures related to the plan required by SFAS No. 132 (revised 2003), until authoritative guidance on the accounting for the federal subsidy is issued. SPR, NPC, and SPPC have elected to defer implementation. As such, any measures of the APBO or net periodic postretirement benefit cost in the consolidated financial statements and notes to consolidated financial statements for SPR, NPC, and SPPC do not reflect the effects of the Act on the plan. Future authoritative guidance on accounting for the subsidy may require changes to previously reported information. Management is unable to determine the financial impact of the Act on the financial position, results of operations or cash flows for SPR, NPC, or SPPC at this time.

NOTE 2. LIQUIDITY MATTERS AND MANAGEMENT'S PLANS

Background

During 2002, the Utilities were severely affected by increased wholesale prices and the related regulatory decisions that denied the Utilities the ability to fully recover incurred fuel and purchased power costs. During the year ended December 31, 2000, and continuing into the first quarter of 2001, the Utilities experienced volatile and unprecedented fuel and purchased power prices. In order to assure adequate supplies of electricity for their customers, the Utilities incurred fuel and purchased power costs in excess of amounts they were permitted to recover in rates. Throughout the year ended December 31, 2000, because the Utilities' allowed recovery was not keeping pace with the cost of providing service, the Utilities sought to adjust their rates to reflect their increased costs. Despite the Utilities' efforts, fuel and purchased power costs continued to escalate and rate recovery could not keep up with the cost of fuel and purchased power. Accordingly, further relief was sought pursuant to legislation and in April 2001, the Governor of Nevada signed into law Assembly Bill 369 (AB 369).

Among other things, AB 369 reinstated deferred energy accounting for electric utilities beginning March 1, 2001. One of the primary objectives of this emergency legislation was to ease the effect of the fluctuations in the price of electricity in the retail market in Nevada and to ensure that the Utilities had the necessary financial resources to provide adequate and reliable electric service under the then present market conditions.

By September 30, 2001, the end of the first period for which a deferred energy application was required to be filed for NPC, NPC had accumulated approximately $922 million of unrecovered fuel and purchased power costs. Similarly, by November 30, 2001, the end of the first period for which SPPC could request recovery of accumulated deferred fuel and purchase power costs, SPPC had incurred approximately $205 million of such costs. On March 29, 2002, the PUCN disallowed recovery of approximately $434 million of costs included in the request filed by NPC. As a result of this disallowance, NPC wrote off approximately $465 million of deferred energy costs and related carrying charges. The two major national rating agencies immediately downgraded the credit ratings of SPR's, NPC's, and SPPC's debt securities (followed by further downgrades in late April 2002), and the market price of SPR's common stock fell substantially. In addition, the May 28, 2002 decision of the PUCN in SPPC's deferred energy rate case, disallowed recovery of $53 million of incurred deferred fuel and purchased power costs.

These events resulted in the termination of the Utilities' commercial paper programs, their unsecured revolving credit facilities as well as the termination of several fuel and power sales contracts by significant suppliers. As of December 31, 2003, asserted claims and judgments for liquidated damages in connection with the terminated contracts (excluding interest) were approximately $385 million. See discussion of the related Enron litigation below. Presently, in order to purchase power and transact with suppliers, NPC and SPPC are generally required to post collateral, prepay or at a minimum, remit payments within a very short period of time. As evidenced by financing transactions consummated in 2003, access to the capital markets to raise funds has been limited, interest rates charged by the market for debt have been higher and accordingly, debt service requirements of SPR, NPC, and SPPC have increased.

Because of long-term purchased power contracts entered into during 2001, both Utilities continued to record additional amounts in their deferral of energy costs accounts during 2002. NPC and SPPC filed the required requests for recovery of these and other deferred fuel and purchased power costs in November 2002 and January 2003, respectively. NPC's application requested recovery of approximately $196 million of deferred costs and SPPC's application sought to recover approximately $15 million of such costs. The decisions in these cases were issued in May 2003 and resulted in further disallowances of approximately $46 million at NPC and an approximate reduction of accumulated deferred costs of $45 million (leaving a balance payable to customers of approximately $30 million) at SPPC.

NOTES TO FINANCIAL STATEMENTS (continued)

Significant Uncertainties

As a result of the matters discussed above as well as other matters related to their business operations, the financial statements of SPR, NPC, and SPPC are subject to significant uncertainties. Management believes that the most significant uncertainties facing SPR and the Utilities in 2004 are:

- whether there will be any further requirements to pay the judgment of the Bankruptcy Court overseeing Enron's bankruptcy proceeding in favor of Enron or to provide further cash collateral, to secure the stay of the judgment against the Utilities pending further appeal,
- whether the Utilities will be able to recover regulatory assets in their current and future rate cases, especially previously incurred deferred fuel and purchased power costs, and to provide sufficient revenues to support their operations,
- whether the Utilities will have sufficient liquidity and the ability in light of certain restrictions to provide dividends to SPR, and
- whether SPR and the Utilities will be able to successfully refinance maturing long-term debt and secure additional liquidity necessary to support their operations, including the purchase of fuel and power.

These uncertainties and management's plans with respect to these matters are discussed in more detail below.

Because of the relationships among the uncertainties described above, an adverse development with respect to a combination of these uncertainties, could have a material adverse effect on SPR's, NPC's, and SPPC's financial condition, results of operations, and liquidity, and could make it difficult for them to continue to operate outside of bankruptcy.

Enron Litigation

As further discussed in Note 15, Commitments and Contingencies, in June 2002, Enron Power Marketing, Inc. (Enron) filed a complaint with the United States Bankruptcy Court for the Southern District of New York (the "Bankruptcy Court") against NPC and SPPC seeking to recover liquidated damages for power supply contracts terminated by Enron in May 2002. 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 agreements with the Utilities. The Judgment requires 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.

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 $281,695 in cash by NPC for prejudgment interest. On December 4, 2003, NPC and SPPC complied with the order of the Bankruptcy Court by issuing their $235 million General and Refunding Mortgage Bond, Series H and $103 million General and Refunding Mortgage Bond, Series E, respectively, into escrow along with the required cash deposits 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 lowered the principal amount of General and Refunding Mortgage Bonds held in escrow by a like amount. NPC and SPPC 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 their deferred energy rate cases. Furthermore, hearings have been scheduled for March 24, 2004, in front of the Bankruptcy Court to review the Utilities' abilities to provide additional cash collateral which, if required, would reduce the principal amount of the General and Refunding Mortgage Bonds held in escrow by a like amount.

It is presently unknown as to whether there will be any further requirement to pay the Judgment or to provide further cash collateral to secure the stay of the judgment against the Utilities pending further appeal. Further, it is uncertain how the court will rule in the pending appeal of the Judgment and if there is an adverse decision in the appeal, whether the Judgment would continue to be stayed pending further appeal.

Liquidity and Financing Matters

NPC anticipates capital requirements for construction costs in 2004 will be approximately $381 million which NPC expects to finance with internally generated funds, including the recovery of deferred energy costs. NPC has $130 million of long-term debt maturing on April 15, 2004. NPC currently expects to refinance all of this debt prior to maturity through the issuance and sale of its General and Refunding Mortgage Securities.

SPPC anticipates capital requirements for construction costs during 2004 totaling approximately $107 million, which SPPC expects to finance with internally generated funds, including the recovery of deferred energy costs. SPPC has $80 million of long-term debt that it will be required to remarket or purchase by May 3, 2004.

Due primarily to the Utilities' weakened financial conditions, the Utilities have been required to pre-pay their power purchases or make more frequent payments for power deliveries. As a result of unseasonably cool weather during the spring of 2003 and its prepayment and more frequent payment obligations for its summer 2003 power requirements, NPC's liquidity was significantly constrained during the early summer months of 2003. Consequently, on June 30, 2003, NPC entered into a $60 million revolving Credit Agreement to provide additional liquidity to NPC for its summer 2003 power purchases. An increase in natural gas prices during SPPC's winter 2003-2004 peak season negatively impacted SPPC's cash flows, which SPPC addressed by issuing and selling its short-term $25 million Series F General and Refunding Mortgage Notes due March 31, 2004. In addition, SPPC entered into a $22 million short-term revolving Credit Agreement which expires March 31, 2004 to provide it with back-up liquidity during this winter peak season.

NPC anticipates that based upon its current cash balances and expected cash flows leading up to the summer 2004 season, NPC may utilize its A/R facility at the onset of the summer 2004 season to support its power purchases. Currently, management believes that NPC will be able to enter into financings and/or credit facilities to meet its summer 2004 cash needs.

SPPC anticipates that based upon its current cash balance and expected cash flows leading up to the summer 2004 peak season, SPPC will not need additional liquidity to support its power and natural gas purchases. Currently, SPPC is exploring the possibility of taking advantage of favorable conditions in the capital markets by entering into new financings to refinance existing debt on more favorable terms and to provide for additional or replacement back-up liquidity facilities.

If the Utilities have to pay significantly higher than expected prices for fuel and purchased power, if their suppliers require significant changes to their current payment terms, or if they do not have sufficient available liquidity to obtain fuel, purchased power and, for SPPC, natural gas, the Utilities may be required to issue or incur additional indebtedness, enter into additional liquidity facilities or utilize their receivables purchase facilities. If they are unable to enter into financings to provide them with sufficient additional liquidity and to repay their maturing indebtedness, whether due to unfavorable conditions in the capital markets, lack of regulatory authority to issue or incur such debt, credit downgrades by either S&P or Moody's resulting from the uncertainties discussed in this section, or restrictive covenants in certain of their financing agreements (see Note 7, Short-Term Borrowings and Note 8, Long-Term Debt), their ability to provide power and fund their expected construction costs and their financial conditions and cash flows will be adversely affected.

SPR does not have any operations of its own and relies on dividends from the Utilities in order to satisfy its debt service obligations. SPR has approximately $70 million of debt service obligations payable during 2004; $22 million, which relate to SPR's 7.25% Convertible Notes due 2010, have been previously provided for through the pledge of U.S. government securities with the trustee at the time the Convertible Notes were issued. See Note 8, Long-Term Debt. Therefore, approximately $48 million of debt service requirements will need to be funded through dividends from the Utilities. Currently, SPR expects to meet its remaining interest obligations for 2004 through the payment of dividends by the Utilities to SPR. In the event that NPC or SPPC is unable to pay dividends to SPR, SPR's liquidity and cash flows would be adversely impacted. See Note 10, Dividend Restrictions for a discussion of the dividend restrictions applicable to the Utilities.

Regulatory Matters

As required, NPC filed its biennial General Rate Case on October 1, 2003. NPC has requested a $133 million increase in the revenue requirement for general rates. Specifically, NPC requested that a $50 million (computed on an annual revenue basis) or 3.4% rate increase commence on April 1, 2004 and continue for nine months. Beginning January 1, 2005, annualized general revenue would then increase by $92 million plus the amount necessary to return $76 million (the estimated amount being deferred (plus interest) during the prior nine month period) over the following 15 months.

On November 14, 2003, NPC filed an application with the PUCN seeking recovery of fuel and purchased power costs accumulated between October 1, 2002 and September 30, 2003. The application sought to establish a rate to collect accumulated costs of $93 million, together with a carrying charge, over a period of not more than three years. The application also requested an increase to the going-forward rate for energy.

On December 1, 2003, SPPC filed an application with the PUCN seeking an electric general rate increase. In the filing, SPPC requested an increase in its general rates charged to all classes of electric customers, which were designed to produce an increase in annual electric revenues of approximately $95 million. Similar to NPC, SPPC is also asking for a staggered implementation of the overall revenue requirement. If approved, SPPC would recover $70 million of the $95 million request in the first year beginning mid-July 2004, delaying the other $25 million, plus a carrying charge, until the next year.

On January 14, 2004, SPPC filed an application with the PUCN seeking to clear approximately $42 million of deferred balances for fuel and purchased power costs accumulated between December 1, 2002, and November 30, 2003. The application requests an asymmetric amortization of the deferred energy balance that would result in recovery of $8 million in the first year, effective mid-July 2004, and $17 million for each of the two years thereafter. The request for resetting the Base Tariff Energy Rate would result in no change to the currently effective rate.

Management believes that they have satisfied the requirements necessary to increase the general rates as requested and that further, fuel and purchased power costs have been prudently incurred; however, management cannot predict the outcome of these proceedings. Material disallowances of deferred energy costs or inadequate base rates would have a significant adverse effect on NPC's and SPPC's financial conditions and future results of operations, could cause additional downgrades of its securities by the rating agencies and make it more difficult to finance operations and to buy fuel and purchased power from third parties.

Management's Plans

Enron Litigation

The Utilities are appealing the judgment of the Enron Bankruptcy Court to the U.S. District Court of the Southern District of New York. In addition, they continue to pursue their FERC Section 206 complaint against Enron. In the event the Utilities were to lose the pending appeal, management currently plans to file an appeal in the U.S. Court of Appeals for the Second Circuit and request that a stay be granted pending the second appeal. In connection with any

NOTES TO FINANCIAL STATEMENTS (continued)

subsequent appeal of the Judgment, the Utilities currently anticipate that they will assert that because of the full protection afforded Enron by the existing collateral, a further stay is warranted, without any material change to the collateral.

Although management believes that the stay of execution of the Judgment will be continued through the appeal process and no significant change will be made to the requirement to post cash collateral, management believes that through financial arrangements currently being negotiated, the Utilities would have the means to meet a substantial payment obligation on the Judgment.

The Utilities expect to enter into a Remarketing Agreement with Enron and one or more investment banks as Remarketing Agent(s) to provide for the remarketing of the Bonds which are presently held in escrow. Although the terms of such a remarketing agreement are not final, management believes that the form of the final agreement will facilitate the successful remarketing of the Bonds to satisfy the Utilities' payment obligations with respect to the Judgment. The Remarketing Agreement will allow Enron, at its option, to require the initiation of a remarketing process with respect to the Bonds and will contain certain provisions that will provide the Utilities with flexibility to modify the terms of the Bonds to attempt a successful initial remarketing effort at the lowest possible interest rate to be determined by the Remarketing Agent(s).

If the Utilities are unsuccessful in the remarketing of the Bonds or if Enron chooses not to have the Bonds remarketed, the Bonds would, from that point forward, accrue interest at 14% and mature in one year; however, Enron would have the right, at any time prior to maturity, to require that the Utilities redeem their bonds at par within four business days. Under the terms of the escrow arrangement between the Utilities and Enron, prior to taking possession of the Bonds, Enron would be required to release the Utilities from any and all payment obligations with respect to the Judgment.

If the appeal process is unsuccessful and the Judgment is ultimately paid, the Utilities plan to pursue recovery of the amounts paid through future deferred energy filings. Determination of the amount of recovery through rates, if any, will be made through the Utilities' usual regulatory process. There is no assurance that the PUCN will allow recovery of any amounts ultimately paid to Enron.

Liquidity and Financing Matters

Based on current market conditions and the history of market access since the credit rating downgrades, management believes that they will be able to successfully refinance the $130 million of NPC's 6.20% Series B, Senior Notes due 2004 maturing on April 15, 2004. Management also believes SPPC will be able to successfully remarket the $80 million of Water Facility Refunding Revenue Bonds prior to May 1, 2004. Management is also giving consideration to obtaining additional funding that would provide for certain amounts of working capital facilities as well as potentially refunding certain debt obligations due in 2005.

On January 21, 2004, NPC filed an application with the PUCN for authority to issue secured long-term debt in an aggregate amount not to exceed $230 million through the period ending December 31, 2004. This authority was requested to allow for the refinancing of the NPC's $130 million 6.20% Series B Senior Notes due 2004, as well as to provide an additional $100 million of liquidity to support utility operations.

On October 9, 2003, NPC filed an application with the PUCN for authority to issue secured or unsecured short-term debt securities in an aggregate amount not to exceed $250 million through the period ending December 31, 2005. This authority was requested to replace the existing short-term debt authority that expired on December 31, 2003. On December 17, 2003, the PUCN issued an order granting NPC the authority to issue up to $250 million in short-term secured or unsecured debt securities. This authority expires December 31, 2005.

Currently, management believes that NPC will be able to enter into financings and/or credit facilities to meet its summer 2004 cash needs. Alternatively, NPC may draw on its accounts receivable facility for additional liquidity. Actual amounts that may be advanced under the receivables purchase facility will vary significantly depending upon, among other things, the time of year, the weather conditions and the delinquency notes of NPC's receivables. Based on 2003 accounts receivables and the variables discussed above, NPC had a maximum capacity of $82 million and minimum capacity of $32 million under the receivables facility. If NPC does not have sufficient liquidity to meet its power requirements, particularly at the onset of the 2004 summer season, NPC may be required to issue or incur additional indebtedness.

On October 9, 2003, SPPC filed an application with the PUCN for authority to issue secured or unsecured short-term debt securities in an aggregate amount not to exceed $250 million through the period ending December 31, 2005. This authority was requested to replace the existing short-term debt authority that expired on December 31, 2003. On December 17, 2003, the PUCN issued an order granting SPPC the authority to issue up to $250 million in short-term secured or unsecured debt securities. This short-term debt authority will expire December 31, 2005.

On December 31, 2003, SPPC filed an application with the PUCN for authority to issue secured long-term debt in an aggregate amount not to exceed $230 million through the period ending December 31, 2004. This authority was requested to allow for the refinancing and remarketing of existing debt securities, as well as to provide additional liquidity to support utility operations.

Currently, management believes that SPPC will be able to internally generate sufficient cash to meets its power procurement cash needs. Alternatively, management believes that SPPC will be able to enter into financings and/or credit facilities or may draw on its accounts receivable facility for additional liquidity. Actual amounts that may be advanced under the receivables purchase facility will vary significantly depending upon, among other things, the time of year, the weather conditions, and the delinquency notes of SPPC's receivables. Based on 2003 accounts receivables and the variables discussed SPPC had a maximum capacity of $28 million and minimum capacity of $13 million under the receivables facility. If SPPC does not have sufficient liquidity to meet its power requirements, SPPC may be required to issue or incur additional indebtedness.

In the PUCN order granting the Utilities each $250 million of short-term financing authority, the PUCN removed the NPC dividend restriction that had previously been in place and replaced it with a restriction limiting the total amount of dividends that could be paid by the Utilities. The PUCN limited cash dividends from NPC and SPPC to an aggregate total of $70 million per year from NPC and/or SPPC to SPR until December 31, 2005.

Moreover, in February 2004, NPC amended the dividend restriction contained 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. As amended, NPC does not anticipate that the First Mortgage Indenture dividend restriction will materially limit the amount of dividends that it may pay to SPR in the foreseeable future.

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 that the Utilities' cash flows will be sufficient, to dividend $48 million to SPR, which is the amount needed in order for SPR to meet its debt service requirements for 2004.

Regulatory Matters

The Utilities have worked diligently to improve their relationships with the PUCN, including undertaking steps to address prior concerns the PUCN expressed in connection with the March 2002 deferred fuel disallowance. In addition to working closely with the staff of the PUCN to keep them apprised of developments and proactively address any potential concerns, the Utilities continue to work closely with the PUCN in implementing new energy risk management and fuel procurement policies, which are designed to stabilize the Utilities' risk exposure in the energy market.

The Utilities' long-term integrated resource plans 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 resource plan was filed with the PUCN on July 1, 2003 and was approved in November 2003. SPPC expects to file its plan in July 2004. The Utilities are required to seek PUCN approval for power purchases with terms of three years or more.

Additionally, the Utilities also seek regulatory input and acknowledgement of intermediate term energy supply plans and resource procurement with a one- to three-year planning horizon. Management believes this is necessary to ensure that the appropriate levels of risks are being mitigated at reasonable costs and are being retained in the portfolio, and decisions to manage risks with the best available information at the point in time when decisions are made are subject to reasonable mechanisms for rate recovery. NPC's energy supply plan was filed with the PUCN on July 1, 2003 with its 2003-2022 resource plan. The resource plan, including NPC's recommended natural gas hedging strategy, was approved by the PUCN on November 12, 2003. SPPC's plan is in the final stages of development and will be filed with the PUCN for informational purposes.

Management believes they have the ability to implement the planned actions and that such actions are designed to mitigate the risks related to the foregoing uncertainties; however, there can be no assurances that management's actions will fully mitigate these risks and uncertainties. The accompanying financial statements do not include any adjustments that might result from the adverse outcome related to the uncertainties discussed above.

NOTE 3. SEGMENT INFORMATION

SPR's Utilities operate three regulated business segments (as defined by FASB Statement No. 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 e·three are reported as discontinued operations in the financial statements for 2003, 2002, and 2001. The net assets and operating results of SPPC's water business, divested in 2001, has been reported as discontinued operations in the financial statements for 2001. Accordingly, the segment information excludes financial information of e·three and SPPC's water business.

NOTES TO FINANCIAL STATEMENTS (continued)

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 of Notes to Financial Statement, Summary of Significant Accounting Policies. Inter-segment revenues are not material (dollars in thousands):

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**	**$161,586**	**$ 3,146**	**$ —**	**$2,789,158**
Operating income	**183,733**	**61,323**	**245,056**	**7,243**	**(4,050)**	**—**	**248,249**
Operating income taxes	**(12,734)**	**(14,288)**	**(27,022)**	**584**	**(43,700)**	**—**	**(70,138)**
Depreciation	**109,655**	**74,432**	**184,087**	**7,082**	**771**	**—**	**191,940**
Interest expense on long-term debt	**142,143**	**69,888**	**212,031**	**6,114**	**77,313**	**—**	**295,458**
Assets	**4,210,759**	**2,061,255**	**6,272,014**	**230,365**	**490,530**	**70,849**	**7,063,758**
Capital expenditures	**227,066**	**123,958**	**351,024**	**22,937**	**—**	**—**	**373,961**

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	$ 3,236	$ —	$2,985,304
Operating income	(104,003)	49,944	(54,059)	5,348	16,662	—	(32,049)
Operating income taxes	(133,411)	(7,236)	(140,647)	314	(27,602)	—	(167,935)
Depreciation	98,198	70,190	168,388	6,183	155	—	174,726
Interest expense on long-term debt	114,527	62,004	176,531	4,470	69,172	—	250,173
Assets	4,166,988	2,104,460	6,271,448	228,067	486,135	124,989	7,110,639
Capital expenditures	294,480	90,343	384,823	14,984	—	—	399,807

December 31, 2001	NPC Electric	SPPC Electric	Total Electric	Gas	All Other	Reconciling Eliminations	Consolidated
Operating revenues	$3,025,103	$1,401,778	$4,426,881	$145,652	$ 2,728	$ —	$4,575,261
Operating income	144,364	71,219	215,583	7,749	(1,609)	—	221,723
Operating income taxes	17,775	5,534	23,309	2,973	(28,046)	—	(1,764)
Depreciation	93,101	66,393	159,494	5,710	604	—	165,808
Interest expense on long-term debt	97,240	53,669	150,909	5,128	51,321	—	207,358
Assets	4,791,261	2,393,284	7,184,545	282,166	580,696	85,320	8,132,727
Capital expenditures	200,852	116,713	317,565	16,041	—	—	333,606

The reconciliation of segment assets at December 31, 2003, 2002, and 2001 to the consolidated total includes the following unallocated amounts:

	2003	2002	2001
Cash	**$29,635**	$ 98,515	$11,772
Current assets—other	**—**	—	50,862
Other regulatory assets	**31,812**	24,555	—
Net assets—discontinued operations	**—**	—	22,626
Deferred charges—other	**9,402**	1,919	60
	$70,849	$124,989	$85,320

NOTE 4. 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 gas and electric distribution and transmission operations. NPC and SPPC submit integrated resource plans (IRP) 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.

Deferred Energy Accounting

On April 18, 2001, the Governor of Nevada signed into law AB 369. AB 369 required the Utilities to use deferred energy accounting for their respective electric operations beginning on March 1, 2001. The intent of deferred energy accounting is to ease the effect of fluctuations in the cost of purchased power and fuel.

Nevada Power Company 2001 General Rate Case

On October 1, 2001, NPC filed an application with the PUCN, as required by law, seeking an electric general rate increase. On December 21, 2001, NPC filed a certification to its general rate filing updating costs and revenues pursuant to Nevada regulations. In the certification filing, NPC requested an increase in its general rates charged to all classes of electric customers designed to produce an increase in annual electric revenues of $22.7 million, or an overall 1.7% rate increase. The application also sought a return on common equity (ROE) for NPC's total electric operations of 12.25% and an overall rate of return (ROR) of 9.30%.

On March 27, 2002, the PUCN issued its decision on the general rate application, ordering a $43 million revenue decrease with an ROE of 10.1% and ROR of 8.37%. The effective date for the decision was April 1, 2002. The decision also resulted in adjustments increasing accumulated depreciation by $6.7 million, and the inclusion of approximately $5 million of revenues related to SO2 allowances. The PUCN delayed consideration of recovery of SPR/NPC merger costs until a future rate case. NPC was not granted a carrying charge on these deferred costs. Recovery of costs related to the generation divestiture project, which supported Nevada's now-abandoned utility restructuring policy, were also delayed. A carrying charge was allowed by the PUCN for the delayed recovery of divestiture costs. NPC renewed its request to recover merger related and divestiture costs in its general rate case which was filed on October 1, 2003.

On April 15, 2002, NPC filed a petition for reconsideration with the PUCN. On May 24, 2002, the PUCN issued an order on the petition for reconsideration. The PUCN modified its original order reversing the adjustment to accumulated depreciation of $6.7 million, and decreased the SO2 allowance revenue amortization to $3.2 million per year. Revised rates for these changes went into effect on June 1, 2002.

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 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. The PUCN and NPC are expected to file responding briefs on March 9, 2004. The court has not 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 Commission 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. The Settlement Judge has yet to recommend closure of the settlement process given current caseloads at the Supreme Court. Briefing, oral argument and a decision are not expected to occur until 2005. NPC is not able to predict the outcome of the process or of the Supreme Court's deliberation on the matter.

Sierra Pacific Power Company 2001 General Rate Case

On November 30, 2001, as required by law, SPPC filed an application with the PUCN seeking an electric general rate increase. On February 28, 2002, SPPC filed a certification to its general rate filing, updating costs and revenues pursuant to Nevada regulations. In the certification filing, SPPC requested an increase in its general rates charged to all classes of electric customers, which were

NOTES TO FINANCIAL STATEMENTS (continued)

designed to produce an increase in annual electric revenues of $15.9 million representing an overall 2.4% rate increase. The application also sought an ROE for SPPC's total electric operations of 12.25% and an overall ROR of 9.42%.

On May 28, 2002, the PUCN issued its decision on the general rate application, ordering a $15.3 million revenue decrease with an ROE of 10.17% and ROR of 8.61%. The effective date of the decision was June 1, 2002. The PUCN delayed consideration of recovery of SPR/NPC merger costs until a future rate case, and SPPC was not granted a carrying charge on these deferred costs. Recovery of costs related to the generation divestiture project, which supported Nevada's now-abandoned utility restructuring policy, were delayed. A carrying charge was allowed by the PUCN for the delayed recovery of divestiture costs. SPPC renewed its request to recover merger and divestiture costs in its general rate case which was filed on December 1, 2003.

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 Bureau of Consumer Protection 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 Base Tariff Energy Rate 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.

Annual Purchased Gas Cost Adjustment 2003 (SPPC)

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 Balancing Account Adjustment (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 Bureau of Consumer Protection 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 will 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 $0.66375 per therm was approved, an increase from the previous BPGR of $0.05316 per therm. The new rates were implemented November 1, 2003.

Annual Purchased Gas Cost Adjustment 2002 (SPPC)

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 Base Purchased Gas Rate (BPGR) and an increase in its Balancing Account Adjustment charge (BAA) by the same amount. This request would result in no change to revenues or customer rates.

This docket was consolidated for hearing purposes with the Liquid Petroleum Gas Cost Adjustment below.

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.

NOTE 5. INVESTMENTS IN SUBSIDIARIES AND OTHER PROPERTY

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

Sierra Pacific Resources

December 31,	2003	2002
Investment in TGTC	$ 31,016	$ 26,912
Non-utility property of SPC	36,512	68,353
Cash value-life insurance	13,065	12,560
Non-utility property of NEICO	3,474	6,555
NVPCT-I & NVPCT-III	5,841	5,841
Southern Service Center Property	12,143	—
Other non-utility property	7,591	10,200
	$109,642	$130,421

Nevada Power

December 31,	2003	2002
Cash value-life Insurance	$13,065	$12,560
Non-utility property of NEICO	3,474	6,555
NVPCT-I & NVPCT-III	5,841	5,841
Southern Service Center Property	12,143	—
Non-utility property	1,789	1,180
	$36,312	$26,136

Sierra Pacific Power

December 31,	2003	2002
Non-utility property	$916	$874

NOTE 6. JOINTLY OWNED FACILITIES

At December 31, 2003, NPC and SPPC owned the following undivided interests in jointly owned electric utility facilities:

Generating Facility	% Owned	Plant-in-Service	Accumulated Depreciation	Net Plant-in-Service	Construction Work in Progress
NPC					
Navajo Station	11.3	$205,508	$105,549	$ 99,959	$3,031
Mohave Facility	14	86,108	45,655	40,453	2,890
Reid Gardner No. 4	32.2	123,832	67,295	56,537	298
Total NPC		$415,448	$218,499	$196,949	$6,219
SPPC					
Valmy Station	50	$284,709	$140,784	$143,925	$1,885

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.

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.

NOTES TO FINANCIAL STATEMENTS (continued)

NOTE 7. SHORT-TERM BORROWINGS

Sierra Pacific Resources

On April 3, 2002, SPR terminated its $75 million unsecured revolving credit facility in connection with the amendment of NPC's $200 million unsecured revolving credit facility, discussed below.

Nevada Power Company

Revolving Credit Facilities

On November 29, 2001, NPC put into place a $200 million unsecured revolving credit facility for working capital and general corporate purposes, including commercial paper backup. As a result of NPC's rate case decisions (discussed in Note 4 of Notes to Financial Statements, Regulatory Actions) and the credit downgrades by S&P and Moody's, which occurred on March 29 and April 1, 2002, respectively, the banks participating in NPC's credit facility determined that a material adverse event had occurred with respect to NPC, thereby precluding NPC from borrowing funds under its credit facility. The banks agreed to waive the consequences of the material adverse event in a waiver letter and amendment that was executed on April 3, 2002. As required under the waiver letter and amendment, NPC issued and delivered its General and Refunding Mortgage Bond, Series C, due November 28, 2002, in the principal amount of $200 million, to the Administrative Agent for the credit facility.

As of September 30, 2002, NPC had borrowed the entire $200 million of funds available under its credit facility at an average interest rate of 3.72%.

On October 30, 2002, NPC paid in full and terminated its $200 million credit facility and retired its Series C, General and Refunding Mortgage Bond which secured the credit facility with the proceeds from the issuance of NPC's $250 million aggregate principal amount of 10⅞% General and Refunding Notes, Series E, due 2009.

On June 30, 2003, NPC entered into a $60 million revolving Credit Agreement to provide additional liquidity to NPC for its summer 2003 power purchases. This facility was paid off on August 11, 2003, and was terminated on August 18, 2003.

Accounts Receivable Facility

On October 29, 2002, NPC established an accounts receivable purchase facility of up to $125 million. Actual amounts that may be advanced under the receivables purchase facilities will vary significantly depending upon, among other things, the time of year, the weather conditions and the delinquency notes of NPC's receivables. Based on 2003 accounts receivables and the variables discussed above, NPC had a maximum capacity of $82 million and minimum capacity of $32 million under the receivables facility. The receivables purchase facility was renewed on October 28, 2003, and expires as of October 26, 2004. If NPC elects to activate the receivables purchase facility, NPC will sell all of its accounts receivable generated from the sale of electricity to customers to its newly created bankruptcy-remote special purpose subsidiary. The receivables sales will be without recourse except for breaches of customary representations and warranties made at the time of sale. The subsidiary will, in turn, sell these receivables to a bankruptcy-remote subsidiary of SPR. SPR's subsidiary will issue variable rate revolving notes backed by the purchased receivables.

The agreements relating to the receivables purchase facility contain various conditions to purchase, covenants and trigger events, and other provisions customary in receivables transactions. In addition to customary termination and mandatory repurchase events, the receivables purchase facility may terminate in the event that either NPC or SPR defaults: (1) on the payment of indebtedness, or (2) on the payment of amounts due under a swap agreement, and such defaults aggregate to greater than $10 million and $5 million for NPC and SPR, respectively.

Under the terms of the agreements relating to the receivables purchase facility, NPC's facility may not be activated or, if activated, will be terminated in the event of a material adverse change in the condition, operations or business prospects of NPC. In addition, the agreements contain a limitation on the payment of dividends by NPC to SPR that is identical to the limitation contained in NPC's General and Refunding Mortgage Notes, Series E, described below. SPR has agreed to guaranty NPC's performance of certain obligations as a seller and servicer under the receivables purchase facility.

NPC has agreed to issue a $125 million General and Refunding Mortgage Bond upon activation of the receivables purchase facility. The full principal amount of the bond would secure certain of NPC's obligations as seller and servicer, plus certain interest, fees, and expenses thereon to the extent not paid when due, regardless of the actual amounts owing with respect to the secured obligations. As a result, in the event of an NPC bankruptcy or liquidation, the holder of the bond securing the receivables purchase facility may recover more on a pro rata basis than the holders of other General and Refunding Mortgage securities, who could recover less on a pro rata basis than they otherwise would recover. However, in no event will the holder of the bond recover more than the amount of obligations secured by the bond.

NPC intends to use the accounts receivable purchase facility as a back-up liquidity facility and does not plan to activate this facility in the foreseeable future. NPC may activate the facility within five days upon the delivery of certain customary funding documentation and the delivery of the $125 million General and Refunding Mortgage Bond. As of February 29, 2004, this facility had not been activated.

Sierra Pacific Power Company

Revolving Credit Facilities

On November 29, 2001, SPPC put into place a $150 million unsecured revolving credit facility for working capital and general corporate purposes, including commercial paper backup. Under this credit facility, SPPC was required, in the event of a ratings downgrade of its senior unsecured debt, to secure the facility with General and Refunding Mortgage Bonds. In satisfaction of its obligation to secure the credit facility, on April 8, 2002, SPPC issued and delivered its General and Refunding Mortgage Bond, Series B, due November 28, 2002, in the principal amount of $150 million, to the Administrative Agent for the credit facility.

As of September 30, 2002, SPPC had borrowed the entire $150 million of funds available under its credit facility to, in part, pay off maturing commercial paper, and to maintain a cash balance at SPPC at an average interest rate of 3.69%.

On October 31, 2002, SPPC paid off and terminated its $150 million credit facility and retired its Series B, General and Refunding Mortgage Bond which secured the credit facility with a combination of cash on hand and proceeds from its $100 million Term Loan Facility.

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. Borrowings under the Series G Note will be used to provide back-up liquidity for SPPC during its 2003-2004 winter peak. Currently, SPPC does not expect to borrow under this facility. The terms of the Series G Note are substantially similar to SPPC's Term Loan Facility. See Note 8 of Notes to Financial Statements, Long-Term Debt, for further discussion.

Short-Term Financing

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 are substantially similar to SPPC's Term Loan Facility.

Accounts Receivable Facility

On October 29, 2002, SPPC established an accounts receivable purchase facility of up to $75 million. Actual amounts that may be advanced under the receivables purchase facilities will vary significantly depending upon, among other things, the time of year, the weather conditions, and the delinquency notes of SPPC's receivables. Based on 2003 accounts receivables and the variables discussed above SPPC had a maximum capacity of $28 million and minimum capacity of $13 million under the receivables facility. The receivables purchase facility was renewed on October 28, 2003, and expires on October 26, 2004. If SPPC elects to activate the receivables purchase facility, SPPC will sell all of its accounts receivable generated from the sale of electricity and natural gas to customers to its newly created bankruptcy-remote special purpose subsidiary. The receivables sales will be without recourse except for breaches of customary representations and warranties made at the time of sale. The subsidiary will, in turn, sell these receivables to a bankruptcy-remote subsidiary of SPR. SPR's subsidiary will issue variable rate revolving notes backed by the purchased receivables.

The agreements relating to the receivables purchase facility contain various conditions to purchase, covenants and trigger events, and other provisions customary in receivables transactions. In additional to customary termination and mandatory repurchase events, the receivables purchase facility may terminate in the event that either SPPC or SPR defaults: (1) on the payment of indebtedness, or (2) on the payment of amounts due under a swap agreement, and such defaults aggregate to greater than $10 million and $5 million for SPPC and SPR, respectively.

Under the terms of the agreements relating to the receivables purchase facility, SPPC's facility may not be activated or, if activated, will be terminated in the event of a material adverse change in the condition, operations or business prospects of SPPC. In addition, the agreements contain a limitation on the payment of dividends by SPPC to SPR that is identical to the limitation contained in SPPC's Term Loan Agreement, described below. SPR has agreed to guaranty SPPC's performance of certain obligations as a seller and servicer under the receivables purchase facility.

SPPC has agreed to issue $75 million principal amount of its General and Refunding Mortgage Bonds upon activation of the receivables purchase facility. The full principal amount of the bond would secure certain of SPPC's obligations as seller and servicer, plus certain interest, fees and expenses thereon to the extent not paid when due, regardless of the actual amounts owing with respect to the secured obligations. As a result, in the event of an SPPC bankruptcy or liquidation, the holder of the bond securing the receivables purchase facility may recover more on a pro rata basis than the holders of other General and Refunding Mortgage securities, who could recover less on a pro rata basis, than they otherwise would recover. However, in no event will the holder of the bond recover more than the amount of obligations secured by the bond.

SPPC intends to use the accounts receivable purchase facility as a back-up liquidity facility and does not plan to activate this facility in the foreseeable future. SPPC may activate the facility within five days upon the delivery of certain customary funding documentation and the delivery of the $75 million General and Refunding Mortgage Bond. As of February 29, 2004, this facility had not been activated.

NOTE 8. LONG-TERM DEBT

As of December 31, 2003 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
2004	$ 135,570	$ 83,400	$ 19,666	$ 238,636
2005	6,091	100,400	300,000	406,491
2006	6,509	52,400	—	58,909
2007	5,949	2,400	240,218	248,567
2008	7,066	322,400	—	329,466
	161,185	561,000	559,884	1,282,069
Thereafter	1,886,023	437,850	300,000(1)	2,623,873
	2,047,208	998,850	859,884	3,905,942
Unamortized (Discount Amount)	(11,929)	(2,650)	(7,171)	(21,750)
Total	$2,035,279	$996,200	$852,713	$3,884,192

(1) SPR's "Thereafter" amount of $300 million represents the total amount of the 7.25% Convertible Notes due at maturity. This differs from the carrying value of $234,118 million included in the balance sheet amount of long-term debt, which is being accreted to face value using the effective interest method.

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.

NOTES TO FINANCIAL STATEMENTS (continued)

Nevada Power Company

On May 24, 2001, NPC issued $350 million of its 8.25% General and Refunding Mortgage Bonds, Series A, due June 1, 2011. The bonds were issued with registration rights and secured by a General and Refunding Mortgage Indenture dated as of May 1, 2001 that is subject to the prior lien of NPC's Indenture of Mortgage dated as of October 1, 1953. On January 29, 2002, NPC exchanged these bonds for identical bonds, registered under the Securities Act of 1933.

On September 20, 2001 and October 15, 2001, NPC issued an aggregate total of $210 million of 6% unsecured notes due September 15, 2003. NPC satisfied its obligations with respect to these notes with a portion of the proceeds from the sale of its 9% General and Refunding Mortgage Notes, Series G, due 2013, discussed below.

On October 18, 2001, NPC issued $140 million of its General and Refunding Mortgage Notes, Floating Rate, Series B, due October 15, 2003. NPC satisfied its obligations with respect to these notes with a portion of the proceeds from the sale of its 9% General and Refunding Mortgage Notes, Series G, due 2013, discussed below.

On May 13, 2000, NPC issued a General and Refunding Mortgage Bond, Series D, due April 15, 2004, in the principal amount of $130 million, for the benefit of the holders of NPC's 6.20% Senior Unsecured Notes, Series B, due April 15, 2004. The Senior Unsecured Notes Indenture required that in the event that NPC issued debt secured by liens on NPC's operating property, in excess of 15% of its Net Tangible Assets or Capitalization (as both terms are defined in the Senior Unsecured Notes Indenture), NPC would equally and ratably secure the Senior Unsecured Notes. NPC triggered this negative pledge covenant on April 23, 2002, when it borrowed certain amounts under its secured credit facility.

On October 25, 2002, NPC redeemed its 7⅝% Series L, First Mortgage Bonds in the aggregate principal amount of $15 million.

On October 29, 2002, NPC issued and sold $250 million of its 10⅞% General and Refunding Mortgage Notes, Series E, due 2009 for net proceeds of $235.6 million. The Series E Notes, which were issued with registration rights, were exchanged for registered notes in January 2003. The 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.

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 were issued with registration rights. 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. The Series G Notes will mature August 15, 2013.

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 15 of Notes to Financial Statements, Commitments and Contingencies of the Consolidated Financial Statements, for more information regarding the Enron litigation. The Series H Bond will be held in escrow until such time as the stay order is lifted, entry of an order affirming the judgment and a denial of stay of such order, or a settlement agreement is entered into between NPC and Enron. 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 G Notes.

The Series E and Series G Notes limit the amount of payments in respect of common stock dividends that NPC may pay to SPR. This limitation is discussed in Note 10 of Notes to Financial Statements, Dividend Restrictions.

The terms of the Series E Notes, Series G 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 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 NPC's obligations with respect to energy suppliers, or

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

If NPC's Series E Notes, Series G Notes, or 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 Notes or the Bond remains investment grade.

Among other things, the Series E Notes, Series G 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.

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) due March 31, 2037, extendible to March 31, 2046, under certain conditions, in a principal amount of $122.6 million. As discussed in Note 1, Summary of Significant Accounting Policies, Recent Pronouncements, FIN 46(R) required 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 Nevada Power Company, 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. As discussed in Note 1, Summary of Significant Accounting Policies, Recent Pronouncements, FIN 46(R) required 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

On April 27, 2001, Washoe County, Nevada issued for SPPC's benefit $80 million of Water Facilities Refunding Revenue Bonds, Series 2001, due March 1, 2036. The bonds accrued interest at a term rate of 5.75% per annum from their date of issuance to April 30, 2003. Beginning May 1, 2003, the method of determining the interest rate on the bonds may be converted from time to time in accordance with the related Indenture so that such bonds would, thereafter, bear interest at a daily, weekly, flexible, term or auction rate. The bonds were issued to refund $80 million of Washoe County variable rate Water Facilities Revenue Bonds (Sierra Pacific Power Company Project) Series 1990 on April 30, 2001. On June 11, 2001, SPPC completed the sale of its water business assets including the Project financed by the sale of the bonds. Although SPPC no longer owns the Project, SPPC will continue to bear the obligations and payments for the bonds under the terms of the Financing Agreement dated as of March 1, 2001, between SPPC and Washoe County, Nevada. The bonds were remarketed on May 1, 2003. The interest rate on the bonds was adjusted from the prior 5.75% term rate to a 7.50% term rate for the period of May 1, 2003 to and including May 3, 2004. The bonds will be subject to remarketing on May 3, 2004 and annually each year thereafter and will continue to be included in current maturities of long-term debt. 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 1, 2003 to and including May 3, 2004, SPPC's payment and purchase obligations in respect of the bonds are secured by SPPC's $80 million General and Refunding Mortgage Note, Series D, due 2004.

On May 24, 2001, SPPC issued $320 million of its 8.00% General and Refunding Mortgage Bonds, Series A, due June 1, 2008. The bonds were issued with registration rights under and secured by a General and Refunding Mortgage Indenture dated as of May 1, 2001 that is subject to the prior lien of SPPC's Indenture of Mortgage dated as of December 1, 1940. On January 29, 2002, SPPC exchanged these bonds for identical bonds, registered under the Securities Act of 1933.

On May 23, 2002, SPPC satisfied its obligations with respect to its 2% First Mortgage Bonds due 2011, 5% Series Y First Mortgage Bonds due 2024, and 2% Series Z First Mortgage Bonds due 2004 by depositing $1.2 million, $3.1 million, and $45,000, respectively, with its First Mortgage Trustee. These First Mortgage Bonds were issued to secure loans made to SPPC by the United States under the Rural Electrification Act of 1936, as amended.

On October 30, 2002, SPPC entered into a $100 million Term Loan Agreement. 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 a Series B General and Refunding Mortgage Bond.

NOTES TO FINANCIAL STATEMENTS (continued)

SPPC's Term Loan Agreement limits the amount of dividends that SPPC may pay to SPR. This limitation is discussed in Note 10 of Notes to Financial Statements, Dividend Restrictions.

SPPC's Term Loan Agreement requires that SPPC maintain a ratio of consolidated total debt to consolidated total capitalization at all times during each of the following quarters in an amount not to exceed,

(1) .650 to 1.0 for the fiscal quarters ended December 31, 2002 through December 31, 2003,

(2) .625 to 1.0 for the fiscal quarters ended March 31, 2004 through December 31, 2004, and

(3) .600 to 1.0 for the fiscal quarter ended March 31, 2005 and for fiscal quarter thereafter.

SPPC's Term Loan Agreement also requires that SPPC maintain a consolidated interest coverage ratio for any four consecutive fiscal quarters ending with the fiscal quarter set for below of not less than,

(1) 1.75 to 1.00 for the fiscal quarters ended December 31, 2002, March 31, 2003, and June 30, 2003,

(2) 1.85 to 1.0 for the fiscal quarter ended September 30, 2003,

(3) 2.00 to 1.0 for the fiscal quarter ended December 30, 2003,

(4) 2.25 to 1.0 for the fiscal quarter ended March 31, 2004,

(5) 2.40 to 1.0 for the fiscal quarter ended June 30, 2004,

(6) 2.70 to 1.0 for the fiscal quarter ended September 30, 2004, and

(7) 3.00 to 1.0 for the fiscal quarter ended December 31, 2004 and for each fiscal quarter thereafter.

As of December 31, 2003, SPPC was in compliance with these financial covenants. The Term Loan Facility, which is secured by a $100 million Series C General and Refunding Mortgage Bond, will expire October 31, 2005. Currently, SPPC is exploring the possibility of taking advantage of favorable conditions in the capital markets by entering into new financings to refinance existing debt, including the Term Loan Facility, on more favorable terms. In the event that SPPC does refinance its Term Loan Facility, after the maturity of SPPC's Series F General and Refunding Mortgage Notes due March 31, 2004 and SPPC's Series G General and Refunding Mortgage Note due March 31, 2004, the covenants in the Term Loan Facility will continue to remain in effect under the terms of SPPC's Series E General and Refunding Mortgage Bond (discussed below).

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 15 of Notes to Financial Statements, Commitments and Contingencies for more information regarding the Enron litigation. The Series E Bond will be held in escrow until such time as the stay order is lifted, entry of an order affirming the judgment and a denial of stay of such order, or a settlement agreement is entered into between SPPC and Enron. 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. The terms of the Series E Bond are substantially similar to SPPC's Term Loan Facility.

Sierra Pacific Resources

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. 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.

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. Currently, 4,804,350 PIES and approximately $240 million of senior unsecured notes remain outstanding.

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. See further discussion regarding the forward stock purchase contract in Note 16 of Notes to Financial Statements, Common Stock And Other Paid-In Capital.

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.

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.

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 ($923,000 in aggregate) for each subsequent quarter. 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, 2003, the purchase contract adjustment payment liability was $5.0 million.

On April 20, 2002, $100 million of SPR's floating rate notes matured and were paid in full.

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.

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, 2003 the carrying value of the Convertible Notes is approximately $234 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 $340 million, at an assumed five-day average closing price of $7.97 per share (based upon the last reported sale price of SPR's common stock on February 27, 2004. 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 11 of Notes to Financial Statements, 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 18 of Notes to Financial Statements, 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.

Sierra Pacific Communications

SPC was formed as a Nevada corporation in 1999 to identify and develop business opportunities in telecommunications services and infrastructure. Since that time SPC has developed two distinct businesses. The first is the development of a fiber optic system extending between Salt Lake City, Utah and Sacramento, California (the System) and the second is the Metro Area Network (MAN) business in Las Vegas and Reno, Nevada.

In September 2002, SPC entered into an agreement to purchase and lease certain telecommunications and fiber optic assets from Touch America (TAI), subject to successful completion of the construction, in exchange for SPC's partnership units in Sierra Touch America and the execution of a $35 million promissory note for a total purchase price of $48.5 million. The promissory note accrues interest at 8% per annum. In June 2003, TAI and all its subsidiaries (including STA/TAI) filed for Chapter 11 bankruptcy protection. In July 2003, SPC filed a motion with the Bankruptcy Court for automatic stay relief, specifically to obtain approval of the offset of construction costs and other system-related costs against the promissory note. SPC's position is that no payments are currently due on the note, and that SPC does not have an obligation to make payments on the note during pendency of the motion. STA and the creditors dispute this position. Currently, the parties are engaging in settlement discussions.

NOTES TO FINANCIAL STATEMENTS (continued)

A final hearing date has not been set. The remaining balance included in SPR's current maturities of Long-Term Debt is approximately $19.7 million as of December 31, 2003.

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 purchase power 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, 2003, were as follows (dollars in thousands):

2004	$5,557
2005	6,076
2006	6,494
2007	5,932
2008	7,053
Thereafter	37,475

NOTE 9. FAIR VALUE OF FINANCIAL INSTRUMENTS

The December 31, 2003, 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, 2003, is estimated to be $1.9 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 $1.3 billion at December 31, 2002.

The total fair value of SPPC's consolidated long-term debt at December 31, 2003, is estimated to be $936.5 million (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 $851.5 million as of December 31, 2002.

The total fair value of SPR's consolidated long-term debt at December 31, 2003, is estimated to be $3.88 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 $2.66 billion as of December 31, 2002.

NOTE 10. 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 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 Resources), 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.

- NPC's 10⅞% General and Refunding Mortgage Notes, Series E, due 2009, which were issued on October 29, 2002, NPC's 9% General and Refunding Mortgage Notes, Series G, due 2013, which were issued on August 13, 2003, and NPC's General and Refunding Mortgage Bond, Series H, which was issued December 4, 2003, limit the amount of payments in respect of common stock that NPC may pay to SPR. However, that 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 both series of Notes and the Bond also permit NPC to make payments to SPR in excess of the amounts payable discussed above in an aggregate amount not to exceed: (1) under the Series E Notes, $15 million from the date of the issuance of the Series E Notes, and (2) under the Series G Notes and the Series H Bond, $25 million from the date of the issuance of the Series G Notes and the Series H Bond, 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 Notes, the Series G Notes, or the Series H Bond,
- 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, 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.

If NPC's Series E Notes, Series G 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.

- On October 29, 2002, NPC established an accounts receivable purchase facility, which was renewed on October 28, 2003, and will expire on October 26, 2004. The agreements relating to the receivables purchase facility contain various covenants, including a limitation on payments in respect of common stock by NPC to SPR that is identical to the limitation contained in NPC's General and Refunding Mortgage Notes, Series E and Series G, and NPC's General and Refunding Mortgage Bond, Series H, described above.
- 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

- SPPC's Term Loan Agreement dated October 30, 2002, as amended, which expires October 31, 2005, limits the amount of payments that SPPC may pay to SPR. However, that 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 PIES) provided that those payments do not exceed $90 million, $80 million, and $60 million in the aggregate for the twelve month periods ending on October 30, 2003, 2004, and 2005, respectively. SPPC's General and Refunding Mortgage Bond, Series E, General and Refunding Mortgage Notes, Series F and General and Refunding Mortgage Note, Series G, contain the same dividend restriction as the Term Loan Agreement.

  The Term Loan Agreement, the Series E Bond, the Series F Notes and the Series G Note, also permit SPPC to make payments to SPR in an aggregate amount not to exceed $10 million during the term of the Term Loan Agreement. In addition, SPPC may make payments to SPR in excess of the amounts described above so long as, at the time of the payment and after giving effect to the payment, there are no defaults or events of default under the applicable financing agreement or security, and such amounts, when aggregated with the amount of payments to SPR by SPPC since the date of execution of the such financing agreement or securities, do not exceed the sum of:

  - 50% of SPPC's Consolidated Net Income for the period commencing January 1, 2003, and ending with last day of fiscal quarter most recently completed prior to the date of the contemplated dividend payment, plus
  - the aggregate amount of cash received by SPPC from SPR as equity contributions on its common stock during such period.
- On October 29, 2002, SPPC established an accounts receivable purchase facility, which was renewed on October 28, 2003, and expires on October 26, 2004. The agreements relating to the receivables purchase facility contain various covenants, including a limitation on the payment of dividends by SPPC to SPR that is identical to the limitation contained in SPPC's Term Loan Agreement, described above.
- 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 December 17, 2003, the PUCN issued an order in connection with its authorization of the issuance of short-term debt securities by NPC and SPPC. The PUCN order, for Dockets 03-10022 and 03-10023, permits NPC and SPPC to dividend an aggregate of $70 million per year to SPR through December 31, 2005. The PUCN order also provides that the dividend limitation may be reviewed in a subsequent application to grant short-term debt authority and that, in the event

NOTES TO FINANCIAL STATEMENTS (continued)

that exigent circumstances are experienced 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, as applied to their particular circumstance 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. The Utilities have the right to seek modification of the conditions of the stay if there is a material change in the facts upon which the stay order is based.

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 Term Loan Agreement and in the financing agreements that contain substantially similar terms as the Term Loan Agreement. The dividend restriction in the PUCN order is the most restrictive provision applicable to both Utilities and may be more restrictive than the individual dividend restrictions if dividends are paid from both Utilities because the $70 million PUCN dividend restriction is less than the aggregate amount of the Utilities' most restrictive individual dividend restrictions.

NOTE 11. 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, 2003 and 2002, 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):

	2003			2002		
	SPR	**NPC**	**SPPC**	SPR	NPC	SPPC
Risk management assets	**$22.1**	**$11.7**	**$10.4**	$29.9	$28.5	$ 1.4
Risk management liabilities	**$16.5**	**$ 5.3**	**$11.2**	$73.9	$29.9	$44.0
Risk management regulatory assets	**$14.3**	**$ 3.1**	**$11.2**	$45.0	$ 1.5	$43.5

Also included in risk management assets were $19.6 million, $9.4 million, and $10.2 million in payments for gas options by SPR, NPC, and SPPC, respectively, at December 31, 2003. In addition, for the year ended December 31, 2003 and 2002, the unrealized gains and losses resulting from the change in the fair value of derivatives designated and qualifying as cash flow hedges for SPR, NPC, and SPPC were recorded in Other Comprehensive Income. Such amounts are reclassified into earnings when the related transactions are settled or terminate. Accordingly, $1.5 million relating to SPR's terminated interest rate swap was reclassified into earnings during the twelve months ended December 31, 2003. The corresponding debt matured in April 2003.

The effects of SFAS No. 133 on comprehensive income have been reported in the consolidated statements of comprehensive income.

In connection with SPR's issuance of its Convertible Notes on February 14, 2003 (see Note 8 of Notes to Financial Statements, 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. 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 twelve months 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 12. INCOME TAXES (BENEFITS)

The following reflects the composition of taxes on income from continuing operations (dollars in thousands):

	2003	2002	2001
As Reflected in Statement of Income:			
Federal income taxes (benefits)			
Current tax expense	**$(10,430)**	$ (92,362)	$(422,261)
Amortization of excess deferred taxes	**(2,196)**	(2,196)	(2,196)
Amortization of investment tax credits	**(3,163)**	(3,454)	(3,520)
Deferred income expense	**(54,349)**	(69,923)	429,377
Total federal income taxes	**(70,138)**	(167,935)	1,400
State income taxes (benefits)	**—**	—	(3,164)
Federal and state income tax (benefits) on operating income	**(70,138)**	(167,935)	(1,764)
Other income—net			
Current tax expense (benefit)	**12,781**	3,778	14,853
Deferred income expense (benefit)	**20**	280	17
Total taxes included in other income—net	**12,801**	4,058	14,870
Total	**$(57,337)**	$(163,877)	$ 13,106

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):

	2003	2002	2001
Income/(loss) from continuing operations	**$(129,375)**	$(300,851)	$32,898
Total income tax expense (benefit)	**(57,337)**	(163,877)	13,106
	(186,712)	(464,728)	46,004
Statutory tax rate	**35%**	35%	35%
Expected income tax expense (benefit)	**(65,349)**	(162,655)	16,101
Depreciation related to difference in costs basis for tax purposes	**4,225**	3,081	2,944
Allowance for funds used during construction—equity	**(2,018)**	112	85
Convertible bond mark to market and interest accretion	**18,291**	—	—
ITC amortization	**(3,163)**	(3,454)	(3,454)
State taxes (net of federal benefit)	**—**	—	(2,057)
Pension benefit plan	**(1,113)**	1,400	697
Other—net	**(5,079)**	(2,361)	(1,210)
	$ (54,206)	$(163,877)	$13,106
Effective tax rate before effect of federal income tax settlement	**29.0%**	35.3%	28.5%
Effects of federal income tax settlement	**(3,131)**	—	—
	$ (57,337)	$(163,877)	$13,106
Effective tax rate	**30.7%**	35.3%	28.5%

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. At December 31, 2003, SPR reached settlements with the IRS for certain matters including the 1997-2001 tax years. As a result of the settlements, SPR recognized tax benefits which increased net income by approximately $3.1 million.

NOTES TO FINANCIAL STATEMENTS (continued)

The net deferred federal income tax liability consists of deferred federal income tax liabilities less related deferred federal income tax assets, as shown (dollars in thousands):

	2003	2002
Deferred Federal Income Tax Assets:		
Net operating loss carryforward	$ 276,554	$ 281,866
Avoided interest capitalized	37,568	32,319
Employee benefit plans	12,415	13,421
Reserve for bad debts	15,721	15,121
Contributions in aid of construction and customer advances	121,171	109,877
Gross-ups received on contribution in aid of construction and customer advances	19,264	16,665
Excess deferred income taxes	17,469	16,460
Unamortized investment tax credit	24,409	26,258
Additional minimum pension liability	16,207	24,905
Deferred amortization of land gain	13,759	—
Provision for contract termination	137,181	109,408
Other	6,775	7,446
	698,493	653,746
Deferred Federal Income Tax Liabilities:		
Allowance for funds used during construction—debt	$ 18,678	$ 16,281
Bond redemptions	10,712	11,132
Excess of tax depreciation over book depreciation	594,171	555,811
Severance programs	5,890	5,019
Tax benefits flowed through to customers	155,547	163,889
Deferred energy	278,229	339,640
Divestiture costs	11,758	—
Ad valorem taxes	3,372	3,336
Merger amortizations	5,836	4,378
Other	19,235	14,642
	1,103,428	1,114,128
Net Deferred Federal Income Tax Liability	$ 404,935	$ 460,382

SPR's balance sheets contain a net regulatory asset of $113.6 million at December 31, 2003 and $121.1 million at December 31, 2002. The net regulatory asset consists of future revenue to be received from customers (a regulatory asset) of $155.5 million at December 31, 2003 and $163.9 million at December 31, 2002, due to flow-through of the tax benefits of temporary differences. Offset against these amounts are future revenues to be refunded to customers (a regulatory liability), consisting of $17.5 million at December 31, 2003 and $16.5 million at December 31, 2002, due to temporary differences for liberalized depreciation at rates in excess of current tax rates, and $24.4 million at December 31, 2003 and $26.3 million at December 31, 2002 due to 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.

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. As of December 31, 2003, unutilized net operating losses (NOLs) were $276.6 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 carryforward period for NOLs incurred is 20 years, and as such the losses incurred in the years ended December 31, 2001, 2002, and 2003 will expire in 2021, 2022, and 2023 respectively.

Based on estimated future taxable income of SPR, the NOL is expected to be fully utilized by 2008. Accordingly, no valuation allowance has been recorded as of December 31, 2003 because it is more likely than not that the NOLs will be fully utilized.

The losses claimed on the tax returns are mainly timing differences, and as such, are not expected to cause a material impact on SPR's, NPC's or SPPC's future income statements if it is determined they are allowable in a subsequent period.

Nevada Power Company

The following reflects the composition of taxes on income (dollars in thousands):

	2003	2002	2001
As Reflected in Statement of Income:			
Federal income taxes (benefits)			
Current tax expense	$ 20,512	$ (45,851)	$(324,725)
Amortization of excess deferred taxes	(499)	(499)	(499)
Amortization of investment tax credits	(1,630)	(1,630)	(1,630)
Deferred income expense	(31,117)	(85,431)	345,569
Total federal income taxes	(12,734)	(133,411)	18,715
State income taxes (benefits)	—	—	(940)
Federal and state income tax (benefits) on operating income	(12,734)	(133,411)	17,775
Other income—net			
Current tax expense (benefit)	12,100	1,347	14,945
Deferred income expense (benefit)	20	280	17
Total taxes included in other income—net	12,120	1,627	14,962
Total	$ (614)	$(131,784)	$ 32,737

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):

	2003	2002	2001
Income/(loss) from continuing operations	**$19,277**	$(235,070)	$63,405
Total income tax expense (benefits)	**(614)**	(131,784)	32,737
	18,663	(366,854)	96,142
Statutory tax rate	**35%**	35%	35%
Expected income tax expense	**6,532**	(128,399)	33,650
Depreciation related to difference in costs basis for tax purposes	**1,431**	1,431	1,431
Allowance for funds used during construction—equity	**(996)**	153	383
State taxes (net of federal benefit)	**—**	—	(611)
ITC amortization	**(1,630)**	(1,630)	(1,630)
Other—net	**(525)**	(3,339)	(486)
	$ 4,812	$(131,784)	$32,737
Effective tax rate before effects of federal income tax settlement	**25.8%**	35.9%	34.1%
Effects of federal income tax settlement	**(5,426)**	—	—
	$ (614)	$(131,784)	$32,737
Effective tax rate	**(3.3)%**	35.9%	34.1%

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. At December 31, 2003, SPR reached settlements with the IRS for certain matters including the 1997-2001 tax years. As a result of the settlements, NPC recognized tax benefits which increased net income by approximately $5.4 million.

The net deferred federal income tax liability consists of deferred federal income tax liabilities less related deferred federal income tax assets, as shown (dollars in thousands):

	2003	2002
Deferred Federal Income Tax Assets:		
Net operating loss carryforwards	**$214,617**	$250,054
Avoided interest capitalized	**19,702**	15,202
Employee benefit plans	**5,936**	9,025
Reserve for bad debts	**14,104**	11,501
Contributions in aid of construction and customer advances	**81,621**	72,018
Gross-ups received on contributions in aid of construction and customer advances	**13,348**	11,054
Excess deferred income taxes	**4,860**	5,360
Unamortized investment tax credit	**10,916**	11,940
Additional minimum pension liability	**1,512**	4,838
Deferred amortization of land gain	**13,759**	—
Provision for contract termination	**99,391**	79,036
Other—net	**(377)**	3,674
	479,389	473,702
Deferred Federal Income Tax Liabilities:		
Allowance for funds used during construction—debt	**$ 10,691**	$ 9,238
Bond redemptions	**4,884**	5,170
Excess of tax depreciation over book depreciation	**347,280**	304,002
Severance programs	**2,606**	2,606
Tax benefits flowed through to customers	**102,282**	106,070
Deferred energy	**216,494**	257,614
Divestiture costs	**7,114**	—
Ad valorem taxes	**3,372**	3,336
Merger amortizations	**2,892**	2,000
Other—net	**4,152**	3,969
	701,767	694,005
Net Deferred Federal Income Tax Liability	**$222,378**	$220,303

NPC's balance sheet contains a net regulatory asset of $86.5 million at December 31, 2003 and $88.8 million at December 31, 2002. The net regulatory asset consists of future revenue to be received from customers (a regulatory asset) of $102.3 million at December 31, 2003 and $106.1 million at December 31, 2002, due to flow-through of the tax benefits of temporary differences. Offset against this amount are future revenues to be refunded to customers (a regulatory liability), consisting of $4.9 million at December 31, 2003 and $5.4 million at December 31, 2002 due to temporary differences for liberalized depreciation at rates in excess of current tax rates, and $10.9 million at December 31, 2003 and $11.9 million at December 31, 2002 due to 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.

NOTES TO FINANCIAL STATEMENTS (continued)

Based on estimated future taxable income of NPC, the NOL is expected to be fully utilized by 2008. Accordingly, no valuation allowance has been recorded as of December 31, 2003 because it is more likely than not that the NOLs will be fully utilized.

Sierra Pacific Power Company

The following reflects the composition of taxes on income (dollars in thousands):

	2003	2002	2001
As Reflected in Statement of Income:			
Federal income taxes (benefits)			
Current tax expense	**$ 9,250**	$(18,909)	$(69,490)
Amortization of excess deferred taxes	**(1,697)**	(1,697)	(1,697)
Amortization of investment tax credits	**(1,533)**	(1,824)	(1,890)
Deferred income expense	**(19,724)**	15,508	83,808
Total federal income taxes	**(13,704)**	(6,922)	10,731
State income taxes (benefits)	**—**	—	(2,224)
Federal and state income tax (benefits) on operating income	**(13,704)**	(6,922)	8,507
Other income—net			
Current tax expense (benefit)	**1,467**	2,431	(91)
Deferred income expense (benefit)	**—**	—	—
Total taxes included in other income—net	**1,467**	2,431	(91)
Total	**$(12,237)**	$ (4,491)	$ 8,416

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):

	2003	2002	2001
Income/(loss) from continuing operations	**$(23,275)**	$(13,968)	$22,743
Total income tax expense (benefit)	**(12,237)**	(4,491)	8,416
	(35,512)	(18,459)	31,159
Statutory tax rate	**35%**	35%	35%
Expected income tax expense (benefit)	**(12,429)**	(6,461)	10,906
Depreciation related to difference in costs basis for tax purposes	**2,794**	1,650	1,513
Allowance for funds used during construction—equity	**(1,022)**	(40)	(298)
ITC amortization	**(1,533)**	(1,824)	(1,824)
State taxes (net of federal benefit)	**—**	—	(1,446)
Pension benefit plan	**(1,113)**	1,400	697
Other—net	**(491)**	784	(1,132)
	$(13,794)	$ (4,491)	$ 8,416
Effective tax rate before effects of federal income tax settlement	**38.8%**	24.3%	27.0%
Effects of federal income tax settlement	**1,557**	—	—
	$(12,237)	$ (4,491)	$ 8,416
Effective tax rate	**34.5%**	24.3%	27.0%

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. At December 31, 2003, SPR reached settlements with the IRS for certain matters including the 1997-2001 tax years. As a result of the settlements, SPPC recognized tax expense, which decreased net income by approximately $1.6 million.

The net deferred federal income tax liability consists of deferred federal income tax liabilities less related deferred federal income tax assets, as shown (dollars in thousands):

	2003	2002
Deferred Federal Income Tax Assets:		
Net operating loss carryforward	**$ —**	$ 237
Avoided interest capitalized	**17,866**	17,117
Employee benefit plans	**6,479**	4,396
Reserve for bad debts	**1,617**	3,620
Contributions in aid of construction and customer advances	**39,550**	37,859
Gross-ups received on contributions in aid of construction and customer advances	**5,916**	5,611
Excess deferred income taxes	**12,609**	11,100
Unamortized investment tax credit	**13,493**	14,318
Additional minimum pension liability	**267**	350
Provision for contract termination	**37,790**	30,372
Other	**2,227**	3,514
	137,814	128,494
Deferred Federal Income Tax Liabilities:		
Allowance for funds used during construction—debt	**$ 7,987**	$ 7,043
Bond redemptions	**5,828**	5,962
Excess of tax depreciation over book depreciation	**246,891**	251,809
Severance programs	**3,284**	2,413
Tax benefits flowed through to customers	**53,265**	57,818
Deferred energy	**61,735**	82,026
Divestiture costs	**4,644**	—
Merger amortizations	**2,944**	2,378
Other	**8,236**	3,423
	394,814	412,872
Net Deferred Federal Income Tax Liability	**$257,000**	$284,378

SPPC's balance sheets contain a net regulatory asset of $27.2 million at December 31, 2003 and $32.4 million at December 31, 2002. The net regulatory asset consists of future revenue to be received from customers (a regulatory asset) of $53.3 million at December 31, 2003 and $57.8 million at December 31, 2002, due to flow-through of the tax benefits of temporary differences. Offset against this amount are future revenues to be refunded to customers (a regulatory liability), consisting of $12.6 million at December 31, 2003 and $11.1 million at December 31, 2002, due to temporary differences for liberalized depreciation at rates in excess of current tax rates, and $13.5 million at December 31, 2003 and $14.3 million at December 31, 2002 due to 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.

Based on estimated future taxable income of SPPC, the NOL is expected to be fully utilized by 2008. Accordingly, no valuation allowance has been recorded as of December 31, 2003, because it is more likely than not that the NOLs will be fully utilized.

NOTE 13. 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 of five years 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	
	2003	2002	**2003**	2002
CHANGE IN BENEFIT OBLIGATIONS				
Benefit obligation, beginning of year	**$428,976**	$360,678	**$132,169**	$ 75,442
Service cost	**15,206**	11,954	**2,455**	1,287
Interest cost	**29,400**	27,733	**8,883**	5,599
Participant contributions	**—**	—	**817**	590
Plan amendment & special termination	**—**	7,938	**—**	—
Actuarial loss	**39,401**	50,670	**22,079**	56,189
Benefits paid	**(17,703)**	(29,997)	**(7,133)**	(6,938)
Benefit obligation, end of year	**$495,280**	$428,976	**$159,270**	$132,169

The accumulated benefit obligations for Pension Benefits at the end of 2003 and 2002 were $397 million and $347 million respectively.

The weighted average actuarial assumptions used to determine end of year benefit obligations are as follows:

	Pension Benefits		Other Postretirement Benefits	
	2003	2002	**2003**	2002
Discount rate	**6.00%**	6.75%	**6.00%**	6.75%
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 2004. The rate was assumed to remain at 6% for all future years.

The discount rate for pension cost purposes is the rate at which the pension obligations could be effectively settled. This rate is based on high-grade bond yields, after allowing for call and default risk. The yields for 30-year Treasury, Merrill Lynch 10+ High Quality, Moody's Aa and Moody's Baa bonds were considered in the selection of the discount rate. SPR elected to use the Moody's Aa composite bond index, which was 5.86% on the plan measurement date of September 30, 2003, to select the discount rate used in calculating benefit obligations. The maturity dates and amounts of this bond index are estimated to be similar to the timing and expected future benefit payments of the plan.

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 (assuming all other assumptions are static) would have the following effect (dollars in thousands):

Effect on the Postretirement Benefit Obligation	2003	2002
Effect of a one-percentage point increase	**$ 19,590**	$ 14,886
Effect of a one-percentage point decrease	**$(16,086)**	$(12,324)

SPR contributions for the Other Postretirement benefits reflect benefit payments made by SPR (dollars in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2003	2002	**2003**	2002
CHANGE IN PLAN ASSETS				
Fair value of plan assets, beginning of year	**$238,834**	$275,305	**$48,425**	$61,406
Actual return on plan assets	**57,964**	(23,090)	**9,709**	(6,817)
SPR contributions	**56,417**	16,616	**222**	183
Participant contributions	**—**	—	**817**	590
Acquisition and divestiture	**—**	—	**—**	—
Benefits paid	**(17,703)**	(29,997)	**(7,133)**	(6,937)
Fair value of plan assets, end of year	**$335,512**	$238,834	**$52,040**	$48,425

NOTES TO FINANCIAL STATEMENTS (continued)

The asset allocation for SPR's pension plans at the end of 2003 and 2002, and the target allocation for 2004, by asset category, follows. The fair value of plan assets for these plans is $335.5 million and $238.8 million, at the end of 2003 and 2002, respectively. The expected long-term rate of return on these plan assets was 8.50% in 2003 and 8.50% in 2002. SPR has established medium and long-term performance objectives for its plan assets to ensure that the returns exceed the actuarial assumption of 8.5%.

	Target Allocation	Percentage of Plan Assets at Year End	
Asset Category	2004	**2003**	2002
Equity securities	60%	**60.8%**	56.4%
Fixed securities	40%	**39.2%**	43.6%
Total	100%	**100%**	100%

The asset allocation for the other postretirement benefit plans at the end of 2003 and 2002, and target allocation for 2004, by asset category, follows. The fair value of plan assets for these plans is $52.0 million and $48.4 million at the end of 2003 and 2002, respectively. The expected long-term rate of return on these plan assets was 8.50% in both 2003 and 2002.

	Target Allocation	Percentage of Plan Assets at Year End	
Asset Category	2004	**2003**	2002
Equity securities	60%	**60.8%**	73.5%
Fixed income securities	40%	**39.2%**	26.5%
Total	100%	**100%**	100%

The basic principles directing SPR's management of the pension and other postretirement plan assets are ensuring the safety of the principal of the assets and obtaining 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, derivatives, and SPR's own stock. Currently, the plan assets are invested in international and domestic equity securities, and fixed securities which include bonds.

Asset allocation is based on long-term capital market behavior and the liquidity needs of the plan. The financial implications of a wide range of investment alternatives (conservative to aggressive) are evaluated over various time periods. Return, risk and diversification assumptions are established for equities and fixed income. The key decisions focus on balancing the rewards of normal market behavior against the risks of poor market behavior over a three-to-seven year planning period.

Funded Status (dollars in thousands)

	Pension Benefits		Other Postretirement Benefits	
	2003	2002	**2003**	2002
Funded status, end of year	**$(159,768)**	$(190,142)	**$(107,230)**	$(83,744)
Unrecognized net actuarial losses	**146,708**	154,222	**74,676**	61,553
Unrecognized prior service cost	**15,036**	17,001	**660**	724
Unrecognized net transition obligation	**—**	—	**8,342**	9,311
Contributions made in 4th quarter	**40,313**	24,495	**—**	—
Accrued pension and postretirement benefit obligations	**$ 42,289**	$ 5,576	**$ (23,552)**	$(12,156)

Amounts for pension and postretirement benefits recognized in the consolidated balance sheets consist of the following (dollars in thousands):

	Pension Benefits		Other Postretirement Benefits	
	2003	2002	**2003**	2002
Prepaid pension asset	**$ 57,465**	$ 19,813	**N/A**	N/A
Accrued benefit liability	**(15,176)**	(14,237)	**$(23,552)**	$(12,156)
Intangible asset	**15,036**	17,001	**N/A**	N/A
Accumulated other comprehensive income	**48,344**	72,550	**N/A**	N/A
Additional minimum liability	**(63,380)**	(89,551)	**N/A**	N/A
Net amount recognized	**$ 42,289**	$ 5,576	**$(23,552)**	$(12,156)

At the end of 2003 and 2002, 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 and Accumulated Benefit Obligation Exceeds the Fair Value of Plan's Assets	
End of Year	**2003**	2002
Projected benefit obligation	**$495,280**	$428,976
Accumulated benefit obligation	**$396,916**	$346,687
Fair value of plan assets	**$335,512**	$238,834

The accumulated postretirement benefit obligation exceeds plan assets for all of SPR's other postretirement benefit plans.

Expected Cash Flows (dollars in thousands)

Information about the expected cash flows for the pension and other postretirement benefit plans follow:

	Pension Benefits	Other Benefits
EMPLOYER CONTRIBUTIONS TO FUNDED PLANS		
2004 (expected)	$ 35,500	$ 233
EXPECTED BENEFIT PAYMENTS		
2004	$ 18,293	$ 7,288
2005	18,908	7,651
2006	19,925	7,993
2007	21,262	8,364
2008	22,715	8,704
2009–2013	143,710	49,712

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 employer obligation is almost entirely 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		
	2003	2002	2001
Service cost	**$ 15,206**	$ 11,954	$ 13,494
Interest cost	**29,400**	27,733	27,742
Expected return on assets	**(21,135)**	(22,768)	(28,806)
Amortization of:			
Prior service costs	**1,966**	1,676	1,195
Actuarial losses	**10,086**	2,252	200
Net periodic benefit cost	**35,523**	20,847	13,825
Additional charges:			
Special termination charges	**—**	1,646	394
Total net benefit cost	**$ 35,523**	$ 22,493	$ 14,219

	Other Postretirement Benefits		
	2003	2002	2001
Service cost	**$ 2,455**	$ 1,287	$ 1,922
Interest cost	**8,883**	5,599	6,358
Expected return on assets	**(3,860)**	(5,044)	(6,774)
Amortization of:			
Prior service costs	**63**	187	—
Transition obligation	**969**	969	969
Actuarial losses	**2,866**	—	—
Net periodic benefit cost	**11,376**	2,998	2,475
Additional charges:			
Special termination charges	**—**	58	—
Total net benefit cost	**$11,376**	$ 3,056	$ 2,475

Weighted average assumptions used to determine net periodic cost for indicated years are as follows:

	Pension Benefits			Other Postretirement Benefits		
	2003	2002	2001	**2003**	2002	2001
Discount rate	**6.75%**	7.50%	8.00%	**6.75%**	7.50%	8.00%
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 2004. 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 8.5% in 2004.

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 (dollars in thousands):

One-Percentage Point Change	Increase	Decrease
Effect on service and interest components of net periodic cost	$1,028	$(843)

There were no significant transactions between the plan and the employer or related parties during 2003, 2002, or 2001.

NOTE 14. STOCK COMPENSATION PLANS

At December 31, 2003, 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 on May 16, 1994, provides for the issuance of up to 750,000 of SPR's common shares to key employees through December 31, 2003. On June 19, 2000, shareholders approved an increase of 1,000,000 shares for the executive long-term incentive plan. 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 2003, SPR issued nonqualified stock options and restricted stock under the long-term incentive plan.

NonQualified Stock Options

Elected officers specifically designated by 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 five years after retirement.

NOTES TO FINANCIAL STATEMENTS (continued)

NQSO's granted during 2003 were issued at an option price not less than market value at the date of the grants. The grant of 25,000 options awarded in July 2003, will vest to the participant over six months from the grant date, and the grant 30,000 options awarded in January 2003 were fully vested on the date of grant. The grants 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.

A summary of the status of SPR's nonqualified stock option plan as of December 31, 2003, 2002, and 2001, and changes during the year is presented below:

	2003		2002		2001	
Nonqualified Stock Options	**Shares**	**Weighted Average Exercise Price**	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Outstanding at beginning of year	**1,399,809**	**$16.56**	1,213,958	$18.28	799,428	$19.94
Granted	**55,000**	**$ 5.69**	502,380	$14.05	414,530	$15.08
Exercised	**—**	**—**	—	—	—	—
Forfeited	**82,940**	**$13.25**	316,529	$19.16	—	—
Outstanding at end of year	**1,371,869**	**$16.33**	1,399,809	$16.56	1,213,958	$18.28
Options exercisable at year-end	**1,369,786**	**$16.35**	524,301	$19.07	262,533	$23.03
Weighted average grant date fair value of options granted:(1)						
Average of all grants for:						
2003		**$ 3.61**				
2002				$ 4.56		
2001						$ 3.83

(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 2003, 2002, and 2001:

Year of Option Grant	Average Dividend Yield	Average Expected Volatility	Average Risk-Free Rate of Return	Average Expected Life
2003	0.00%	46.97%	4.64%	10 years
2002	0.00%	38.23%	5.03%	10 years
2001	4.99%	32.31%	5.32%	10 years

The following table summarizes information about nonqualified stock options outstanding at December 31, 2003:

		Options Outstanding		Options Exercisable	
Year of Grant	Average Exercise Price	Number Outstanding at 12/31/03	Remaining Contractual Life	Average Exercise Price	Number Exercisable at 12/31/03
1994	$14.24	8,003	< 1 year	$14.24	8,003
1995	$13.02	9,010	1 year	$13.02	9,010
1996	$16.23	7,485	2 years	$16.23	7,485
1997	$19.97	24,788	3 years	$19.97	24,788
1998	$24.93	48,240	4 years	$24.93	48,240
1999	$25.11	164,206	5-5.6 years	$25.11	164,206
2000	$16.00	400,000	6 years	$16.00	400,000
2001	$15.95	266,187	7-7.9 years	$15.95	266,187
2002	$ 7.99	388,950	8-8.9 years	$ 7.99	388,950
2003	$ 5.65	55,000	9-9.5 years	$ 5.65	52,917
Weighted Average Remaining Contractual Life			6.63 years		

Each participant was granted dividend equivalents for all 1996 and prior nonqualified option grants. 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.

In 2003, all of the outstanding performance shares were converted into shares of restricted stock. As a consequence, there are currently no outstanding grants of performance shares.

Restricted Stock Shares

All of the performance shares outstanding at December 31, 2002 were converted into shares of restricted stock.

In 2003, SPR granted an additional 419,376 shares of restricted stock at an average grant price of $6.57 per share. Of the shares granted, 409,376 shares will vest over four 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 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 2003, according to the vesting schedule for each grant, 1,125 shares were issued under these grants.

During 2001, SPR granted 13,200 shares of restricted stock at an average grant price of $15.72 per share. The grants vest to the participants over four years at 25% per year. In 2003, in accordance with the conditions of each grant, 675 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 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 90% of the market value on the offering commencement date. Employees can withdraw from the plan at any time prior to the exercise date. Under the plan SPR sold 100,660, 73,321, and 33,830 shares to employees in 2003, 2002, and 2001, 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 2003, 2002, and 2001, with an option life of six months:

Year	Average Dividend Yield	Average Expected Volatility	Average Risk-Free Rate of Return	Weighted Average Fair Value
2003	0.00%	52.40%	0.98%	$1.29
2002	0.00%	38.00%	3.12%	$1.45
2001	5.01%	32.43%	2.82%	$2.72

NOTE 15. COMMITMENTS AND CONTINGENCIES (SPR, NPC, AND SPPC)

Purchased Power

At December 31, 2003, NPC has six long-term contracts for the purchase of electric energy. Expiration of these contracts ranges from 2016 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, 2003, 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, 2003, 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 noncancelable agreements (including agreements with QF's as of December 31, 2003 were as follows (dollars in thousands)):

Purchased Power

	NPC	SPPC	Total
2004	$ 358,753	$57,030	$ 415,783
2005	301,222	29,385	330,607
2006	240,848	29,969	270,817
2007	210,797	30,767	241,564
2008	192,374	32,259	224,633
Thereafter	$2,897,461	$ 5,540	$2,903,001

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 2004 to 2027. Estimated future commitments under noncancelable agreements were as follows (dollars in thousands):

	Coal and Gas			Transportation		
	NPC	SPPC	Total	NPC	SPPC	Total
2004	$57,414	$101,025	$158,439	$ 40,025	$ 62,519	$102,544
2005	16,700	18,001	34,701	24,736	57,586	82,322
2006	19,322	18,322	37,644	24,736	52,869	77,605
2007	18,000	—	18,000	24,736	52,822	77,558
2008	—	—	—	24,736	45,684	70,420
Thereafter	$ —	$ —	$ —	$245,764	$255,662	$501,426

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 noncancelable operating leases as of December 31, 2003, were as follows (dollars in thousands):

	Operating Leases			
	NPC	SPPC	Other Subs	Total
2004	$1,909	$ 8,152	$177	$10,238
2005	1,501	7,553	—	9,054
2006	936	7,197	—	8,133
2007	35	5,965	—	6,000
2008	8	5,966	—	5,974
Thereafter	$ 450	$22,153	$ —	$22,603

NOTES TO FINANCIAL STATEMENTS (continued)

Other

On December 18, 2003, SPPC entered into a 15-year Transportation Service Agreement (the Agreement) with Tuscarora Gas Transmission Company, a related company. The agreement calls for SPPC to take 23,000 dth/day of capacity beginning in the winter of 2005.

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 controls 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 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 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. In July, NPC filed an IRP with the PUCN that assumed 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 net book value of $40.5 million by end of 2005. Alternatively, NPC requested that the PUCN authorize the transfer of the remaining book value to a regulatory asset account to be amortized over a period as determined by the PUCN.

In May 1997, the 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 approved by NDEP. NDEP was originally expected to identify remediation requirements of contaminated groundwater resulting from these evaporation ponds by September 2003. Recently, NDEP indicated that remediation requirements will be identified by mid-year 2004. New pond construction and lining costs are estimated to cost approximately $25 million, of which, a majority is expected to be spent by the end of 2004.

At the Reid Gardner Station, NDEP has determined that there is additional groundwater contamination that resulted from oil spills at the facility. NDEP required NPC to submit a corrective action plan. A hydro-geologic evaluation of the current remediation was completed, and a dual phase extraction remediation system, which was approved by NDEP, commenced operation in October 2003.

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. It is NPC's position that a violation did not occur and management is presently involved in the discovery process to support management's 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 $4.8 million with the Utah Division of Oil and Gas Mining. Currently, management is continuing to evaluate various options including reclamation and sale. At this time the maximum financial impact on the Company is $4.8 million.

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 PRPs formed a steering committee, which is chaired by SPPC. The steering committee has completed its site investigations and 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. SPPC recorded a preliminary liability for the Sites of $650,000. The steering committee is obtaining cost estimates for removal of the buildings. Once these costs have been determined, SPPC will be in a better position to estimate and revise, if necessary, its recorded liability for the Sites.

Lands of Sierra

LOS, a wholly owned subsidiary of SPR, owns property in North Lake Tahoe, California, which is leased to independent condominium owners. The property has both soil and groundwater petroleum contamination resulting from an underground fuel tank that was removed from the property. Additional contamination from a third party fuel tank on the property has also been identified and is undergoing remediation. On February 3, 2003, the Lahontan Regional Water Quality Control Board re-opened the case against this property. The re-opening occurred due to onsite monitoring, which showed increased levels of contamination. SPR has completed the evaluation of alternative remediation technologies and their effectiveness in reducing contamination at this site. On January 27, 2004, Lahontan Regional Water Quality Board rendered a decision requiring a dual phase water extraction remediation system. The cost to implement this system is not material.

Litigation Contingencies

Nevada Power Company and Sierra Pacific Power Company

Enron Litigation

In June 2002, Enron filed a complaint with the Bankruptcy Court against NPC and SPPC (the Utilities) seeking to recover liquidated damages for power supply contracts terminated by Enron in May 2002 and for unpaid power previously delivered to the Utilities (as defined below). The Utilities denied liability on numerous grounds, including deceit and misrepresentation in the inducement (including, but not limited to, misrepresentation as to Enron's ability to perform) and fraud, unfair trade practices and market manipulation. The Utilities also filed proofs of claims and counterclaims against Enron, for the full amount of the approximately $300 million claimed to be owed and additional damages, as well as for other unspecified damages to be determined during the case as a result of acts and omissions of Enron in manipulating the power markets, wrongful termination of its transactions with the Utilities, and fraudulent inducement to enter into transactions with Enron, among other issues.

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 agreements with the Utilities. The Judgment requires 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. The Bankruptcy Court also dismissed the Utilities' counter-claims against Enron, dismissed the Utilities' counter-claims against Enron Corp., the parent of Enron, and denied the Utilities' motion to dismiss or stay the proceedings pending the final outcome of their FERC proceedings against Enron. 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 provides 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 $281,695 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 their $235 million General and Refunding Mortgage Bond, Series H and $103 million General and Refunding Mortgage Bond, Series E, respectively, into escrow along with the required cash deposits 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 will lower the principal amount of General and Refunding Mortgage Bonds held in escrow by a like amount. NPC and SPPC 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 their deferred energy rate cases. Furthermore, hearings have been scheduled for March 24, 2004, in front of the Bankruptcy Court to review the Utilities' abilities to provide additional cash collateral which, if required, would reduce the principal amount of the General and Refunding Mortgage Bonds held in escrow by a like amount.

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. On its appeal the Utilities seek reversal of the Judgment and contend that Enron is not entitled to recover termination

NOTES TO FINANCIAL STATEMENTS (continued)

charges under the contract 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. The Utilities filed their principal brief on December 30, 2003 and Enron filed its cross-appeal brief and reply brief on January 30, 2004. The Utilities filed a reply brief on March 1, 2004 and Enron is expected to file its final brief thereafter in March 2004. The U.S. District Court could render an opinion any time after the submission of the final briefs. The Utilities are unable to predict the outcome of their appeal of the Judgment.

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. The PUCN ruled that "...paying into escrow while pursuing an appeal of the Bankruptcy Court's judgment and other relief does not yet provide the circumstances of experiencing a cost which can trigger a filing seeking collection from its customer, and because the issues are not ripe, this Petition is not the docket to decide whether recovery of termination payments should be sought through a general rate case or a deferred energy proceeding."

Through December 31, 2003, interest costs related to the Judgment of $36 million and $16 million for NPC and SPPC, respectively, were charged as interest expense and were not included in their deferred energy balances. If the Utilities are successful in their appeal, amounts previously charged to interest expense would be reversed and recognized in income in the respective period. Similarly amounts for power supply contracts terminated by Enron included in the deferred energy balances would be reversed. If the Utilities are unsuccessful in their appeal, they may seek to recover the interest costs in the deferred account.

Any requirement to pay the Judgment or to provide further cash collateral, described above, for Enron's claims for termination payments could adversely affect SPR's, NPC's, and SPPC's cash flow, financial condition and liquidity, and could make it difficult for one or more of SPR, NPC, or SPPC to continue to operate outside of bankruptcy.

FERC 206 Complaints

In December 2001, the Utilities filed ten wholesale-purchased power complaints with the FERC under Section 206 of the Federal Power Act seeking to reduce prices of certain forward 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 utility 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 have already paid the full contract price for all power actually delivered by these suppliers, but are contesting those amounts as well as claims made for terminating power suppliers that did not deliver power, including those terminated by Enron.

The Administrative Law Judge (ALJ) overseeing the Utilities' complaints and proceedings under Section 206 of the Federal Power Act issued an initial decision on December 19, 2002, which stated that the Utilities' complaints did not meet the public interest standard of proof, which the ALJ believed applied to the reformation of their contracts. NPC, SPPC, and other parties to these proceedings filed Briefs on Exceptions to the ALJ's initial order with the FERC.

On June 26, 2003, FERC adopted the ALJ's recommendation and dismissed the Utilities' Section 206 complaints on a two-to-one vote essentially finding that the strict public interest standard applied to the case and that the Utilities had failed to satisfy the burden of proof required by that standard. In that order, FERC also determined that it would not deem the order final and conclusive as to either of the Utilities' liability to Enron for purchase power contracts terminated by Enron, which may be challenged in other proceedings, including other proceedings at FERC. On July 28, 2003, the Utilities filed a petition for rehearing at the FERC requesting that the FERC either reconsider or rehear the case. The petition cited several grounds for rehearing, including that the public interest standard did not apply but that even if it did apply the Utilities had satisfied that standard as well as the less onerous just and reasonable standard which the Utilities contend does apply to the case. On November 10, 2003, the FERC issued an Order on Requests for Rehearing and Clarification, which reaffirmed the June 26, 2003 decision (by the same two-to-one margin). The Utilities intend to pursue available appeals of this matter. Under applicable statutes, the Utilities may seek judicial review before the United States Court of Appeals for the District of Columbia Circuit or the Ninth Circuit. That decision has been appealed to the D.C. Circuit Court of Appeals, which has not yet established a briefing schedule. The Utilities are unable to predict the outcome of this appeal at this time.

On October 6, 2003, the Utilities filed a new FERC Section 206 complaint against Enron to prevent Enron from obtaining a final judgment in the Bankruptcy Court case and/or prevent enforcement of any right to collect its termination payments until FERC has had a chance to review the complaint. The new complaint has been designated as Docket No. EL04-1-000. On October 27, 2003, Enron filed an answer to the Utilities' complaint and the matter is pending. On October 8, 2003, the Nevada Attorney General's office, through its Bureau of Consumer Protection, intervened on behalf of Nevada citizens, joining NPC and SPPC in opposing Enron's actions. On October 29, 2003, United States Senators Reid and Ensign of Nevada also filed an intervention joining NPC and SPPC in opposing Enron's claims to termination payments.

Enron was found by the FERC earlier this year to have unlawfully manipulated the Western energy market, engaging in fraud, deception and other actions that created power market prices that were unjust and unreasonable. Prior and subsequent to the FERC ruling, numerous Enron employees pled guilty to related criminal charges.

The 206 complaint in Docket No. EL04-1-000 asks FERC to issue an order to preserve the status quo by prohibiting Enron from enforcing the termination payment obligations set forth in the judgment until such time as FERC has an opportunity to review the merits of the Utilities' claims raised in their new FERC Section 206 complaint. The complaint further asks that FERC find that Enron's actions violated the terms of tariff language rendering Enron unable to collect termination payments; that Enron violated federal law, including the Federal Power Act, and breached FERC's regulations and power tariffs governing the transactions. In addition, the complaint asks FERC to: (a) assert its jurisdiction over the issue of whether Enron may lawfully claim rights under the power deals to be paid for not providing power that it could not provide anyway; (b) issue an order to preserve the status quo by prohibiting Enron from enforcing the termination payment obligations set forth in the judgment until such time as FERC has an opportunity to review the merits of the Utilities' claims raised in their new FERC Section 206 complaint; (c) find that the applicable rules to do not permit the sort of maneuver to create a windfall that Enron has attempted; and (d) find that, even if hypothetically Enron is technically entitled to a payment, it is neither equitable nor in the public interest for the Utilities to be required to pay Enron an additional award in excess of $300 million. At this time, NPC and SPPC are unable to predict either the outcome or timing of a decision in this matter.

Reliant Antitrust Litigation

On April 22, 2002, Reliant Energy Services, Inc. (Reliant), filed and served a cross-complaint against NPC and SPPC in the wholesale electricity antitrust cases, which was 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) in that case 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 is liability, it should spread among all energy suppliers. The trial court has held all answers to cross-claims in abeyance until such time as it decides whether the plaintiffs' complaint should be dismissed for failing to state a claim for relief and whether the complaint should be dismissed under the filed rate doctrine. The court granted the motion to dismiss and the case is currently on appeal.

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 overseeing the arbitration proceedings 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.

On March 26, 2003, 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 FERC alleging that NPC should be required to pay MSCG the amount of the claimed termination payment pending resolution of the case. NPC filed a motion to intervene in the FERC action commenced by MSCG and FERC dismissed MSCG's complaint. NPC is unable to predict the outcome of the District Court complaint.

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 Western System Power Pool Agreement (WSPP) 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. Idaho requested mediation of the contracts. NPC alleges that Idaho and Reliant were participants in market manipulation in the West and therefore are not entitled to termination payments under the contracts. The mediation was not successful and in April 2003 Idaho filed suit in Idaho. NPC moved to dismiss the complaint on jurisdictional grounds and filed its own complaint in State court in Clark County, Nevada in September 2003. The court in Idaho denied NPC's motion to dismiss without prejudice and ordered some preliminary discovery on the jurisdictional issues. The case in Nevada is currently pending.

In June 2003, Reliant Energy submitted a comprehensive settlement proposal to NPC proposing a settlement of NPC's termination payment obligation arising out of Reliant's May 2002 termination of its purchase power contracts with NPC. NPC denies that it owes Reliant any money under these contracts. Mediation of this claim occurred in 2002 and was not successful. Neither party has requested arbitration nor commenced litigation over this dispute, and the parties are continuing discussions.

NOTES TO FINANCIAL STATEMENTS (continued)

El Paso Merchant Energy

In August 2002, El Paso Merchant Energy (EPME) terminated contracts for energy it had delivered to NPC under a program that called for delayed payment of the full contract price. In October 2002, EPME asserted a claim against NPC for $19 million in damages representing the approximate amount unpaid under the contracts. NPC alleges that EPME's termination resulted in net payments due to NPC under the WSPP liquidated damages provision as and for liquidated damages measured by the difference between the contract price and market price of energy EPME was to deliver from 2004 to 2012.

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. EPME claims that under the terms of the contracts, NPC owes EPME approximately $39 million representing the difference between the contract price and the market price for power to be delivered under all the terminated contracts and the amount remaining unpaid under the contracts for power delivered between May 2002 and October 2002. NPC claims that EPME owes NPC an amount up to approximately $162 million for undelivered power representing the difference between the replacement price or market price for power to be delivered under all the executory contracts and the contract price for that power. 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. EPME filed a motion to dismiss the complaint on grounds of lack of personal jurisdiction and failure to state a claim for relief. NPC responded to the motion to dismiss on February 27, 2004. EPME's reply is due March 17, 2004. At this time NPC is unable to predict either the outcome or timing of a decision in this matter.

Contract Termination Liabilities

At December 31, 2003, included in NPC's and SPPC's Consolidated Balance Sheets as "Contract termination liabilities," is $280 million and $105 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, 2003, is approximately $245 million and $84 million, (which excludes interest costs discussed below) 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 for, 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 amounts not permitted would be charged as a current operating expense. A significant disallowance of these costs by the PUCN could have a material adverse effect on the future financial position, results of operations, and cash flows of SPR, NPC, and SPPC.

Bonneville Square and Union Plaza

In October 2002, Bonneville Square and Union Plaza filed a complaint seeking class certification in the Eighth District Court for Clark County, Nevada, against NPC for fraud and misrepresentation for allegedly overcharging a certain class of customers for energy delivered over the past several years. Plaintiffs allege that NPC fraudulently placed its meters and measured energy delivered at a point prior to passing through transformers during which process a certain amount of energy is dissipated as heat, instead of placing the meters after they pass through the transformer. Plaintiffs claim that NPC overcharged the class by an indeterminate amount. NPC's motion to dismiss on jurisdictional grounds was denied and NPC filed a writ before the Nevada Supreme Court, which is being joined in by the PUCN, which agrees with NPC that it has exclusive jurisdiction over the suit. NPC denies that the placement of the meters was fraudulent and alleges that placement of the meters was mandated by either or both customer request or applicable tariff. The matter is currently pending.

Sierra Pacific Resources

Gordon and Anderson

On September 30, 2002, plaintiffs Stephen A. Gordon and Gail M. Gordon filed a lawsuit in the District Court for Clark County, Nevada, seeking class action status for themselves and all shareholders of SPR against SPR and all of its directors for an alleged breach of fiduciary duty in failing to meaningfully evaluate and consider an alleged offer from the Southern Nevada Water Authority (SNWA) to purchase Nevada Power Company. The suit seeks extraordinary relief in the form of an injunction requiring the directors to carefully evaluate and consider such offer, formation of a special stockholders committee to ensure fair and adequate evaluation procedures, and for unspecified damages and/or punitive damages in the event the SNWA withdraws its alleged offer before it can be carefully evaluated. SPR intends to vigorously defend the suit. No answer or responsive pleading has yet been required nor have plaintiffs moved for class certification. On September 30, 2002, plaintiff John Anderson filed a virtually identical lawsuit seeking the same relief in the same court. On March 21, 2003, plaintiffs' counsel moved to consolidate the Gordon and Anderson cases with another virtually identical lawsuit filed by John Dedolph, also filed in the same court. In July 2003, the cases were consolidated into one action and moved to the Clark County Business Court. On August 22, 2003, the judge dismissed the consolidated cases against SPR.

Touch America and Sierra Touch America LLC

In 2000, SPC, and TA (formerly Montana Power), formed 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 between Salt Lake City, Utah, and Sacramento, California. The project sustained significant cost overruns and several complaints and mechanics liens have been filed by several contractors and subcontractors, including Williams Communications LLC, Bayport Pipeline Company, and Mastec North America. In September 2002, SPC conveyed its membership interest in STA to Touch America and obtained an indemnity for any liabilities associated with STA, all in exchange for title to several fibers in the line and a $35 million promissory note. Several of the mechanics lienors have named SPC as the owner of the project and Bayport Pipeline has suggested it may amend its complaint to name SPC.

In June 2003, TAI and all its subsidiaries (including STA) filed a petition for Chapter 11 bankruptcy protection. In July 2003, SPC filed a motion with the Bankruptcy Court for automatic stay relief, specifically to obtain approval of the offset of construction costs and other System-related costs against the promissory note. SPC's position is that no payments are currently due on the note, and that SPC does not have an obligation to make payments on the note during the pendency of the motion. STA and the creditors dispute this position. A status conference on the motion is scheduled for March 11, 2004, a final hearing date has not been set.

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 or results of operations.

Regulatory Contingencies

The Utilities' rates are currently subject to the approval of the PUCN and, in the case of SPPC, they are also subject to the approval of CPUC. Such rates are designed to recover the cost of providing generation, transmission, and distribution services. Accordingly, the Utilities qualify for the application of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." See Note 1 of Notes to Financial Statements, Summary of Significant Accounting Policies, for further information.

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 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 of Notes to Financial Statements, Summary of Significant Accounting Policies, management believes the existing regulatory assets are probable of recovery. This determination reflects the current political and regulatory climate in the state, and is subject to change in the future. If future recovery of costs ceases to be probable, the write-off of regulatory assets would be required to be recognized as a charge or expensed in current period earnings.

Regulatory Accounting affects Deferred Energy, Goodwill and Merger Costs, Generation Divestiture Costs, and Piñon Pine, all of which are discussed immediately below. To the extent that the Utilities may not be permitted to recover any portion of deferred energy, goodwill and merger costs, generation divestiture costs and long-lived assets (Piñon Pine), the disallowed costs and related carrying charges would be required to be written off in current period earnings, except for Goodwill, which is subject to evaluation for impairment in accordance with the provisions of SFAS No. 142. A significant disallowance of these costs by the PUCN would have a material adverse effect on the future financial position, results of operations, and cash inflows of SPR, NPC, and SPPC.

Deferred Energy

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 of fluctuations in the cost of purchased gas, fuel, and purchased power.

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.

AB 369 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, AB 369 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. Deferred energy balances subject to PUCN review as of December 31, 2003 are $344 million and $130 million for NPC and SPPC, respectively, including the deferred provision for terminated supply contracts.

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 costs to be reviewed for recovery through future rates. That order specifically directed both Utilities to defer merger transaction costs, transition costs, and goodwill costs for a three-year period. 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 instructs the Utilities to propose an amortization period for the merger costs and allows the Utilities to recover the costs to the extent they are offset by merger savings.

NOTES TO FINANCIAL STATEMENTS (continued)

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 December 31, 2003. The deferred other merger costs consist 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. These amounts are included in NPC's and SPPC's current general rate case. We expect a decision in NPC's case in the later part of March 2004 and late spring 2004 for SPPC.

Generation Divestiture Costs

As a condition to its approval of the merger between SPR and NPC, the Utilities filed, and in February 2000 the PUCN approved, a revised Divestiture Plan stipulation for the sale of the Utilities' generation assets. In May 2000, an agreement was announced for the sale of NPC's 14% undivided interest in the Mohave. In the fourth quarter of 2000, the Utilities announced agreements to sell six additional bundles of generation assets described in the approved Divestiture Plan. The sales were subject to approval and review by various regulatory agencies.

AB 369, which was signed into law on April 18, 2001, prohibited the sale of generation assets until July 2003 and directs the PUCN to vacate any of its orders that had previously approved generation divestiture transactions. In January 2001, California enacted a law that prohibits any further divestiture of generation properties by California utilities until 2006, including SPPC, and could also affect any sale of NPC's interest in Mohave after July 2003 since the majority owner of that project is Southern California Edison. SPPC's request for an exemption from the requirements of a separate California law requiring approval of the CPUC to divest its plants was denied. In September 2002, the California Legislature approved an exemption to AB 6, which had prevented private utilities from selling any power plants that provide energy to California customers until 2006. The exemption allows SPPC to complete the sale of the hydroelectric units to Truckee Meadows Water Authority (TMWA) subject to review and approval of the sale by the CPUC.

The sales agreements for the six bundles provided that they would terminate eighteen months after their execution and all of the agreements have now terminated in accordance with their respective provisions. As of December 31, 2003, NPC and SPPC had incurred costs, including carrying charges, of approximately $21.9 million and $13.3 million, respectively, in order to prepare for the sale of generation assets. In the fourth quarter of 2001, each Utility requested recovery of its respective costs in its application for a general rate increase filed with the PUCN. In 2002, the PUCN delayed recovery of divestiture costs to future rate case requests and granted a carrying charge on the costs until such time as recovery is allowed. To the extent that the Utilities may not be permitted to recover any portion of these costs in future rates, the disallowed costs and related carrying charges would be required to be written off in current period earnings. These amounts are included in NPC's and SPPC's current general rate case. A decision is expected in NPC's case in the later part of March 2004 and late spring 2004 for SPPC.

Piñon Pine

SPPC owns a combined cycle generation facility, a post-gasification facility, and, through its wholly owned subsidiaries, owns a gasifier that are collectively referred to as the Piñon Pine. Construction of Piñon Pine was completed in June 1998. Included in the Consolidated Balance Sheets of SPR and SPPC is the net book value of the gasifier and related assets, which is approximately $95 million as of December 31, 2003.

To date, SPPC has not been successful in obtaining sustained operation of the gasifier. In 2001, SPPC retained an independent engineering consulting firm to complete a comprehensive study of the Piñon Pine gasification plant. After evaluating the options presented in the draft report, SPPC decided not to pursue modifications intended to make the facility operational and is seeking recovery, net of salvage, through regulated rates in its general rate case, which was filed on December 1, 2003, based, in part, on the PUCN's approval of Piñon Pine as a demonstration project in an earlier IRP. However, if SPPC is unsuccessful in obtaining recovery, there could be a material adverse effect on SPPC's and SPR's results of operations.

NOTE 16. 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, 2003, 8,316,624 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 (ELTIP).

The ELTIP for key management employees allows for the issuance of SPR's common shares to key employees through December 31, 2003, which can be earned and issued after December 31, 2003. 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 and bonus stock.

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 2003, 2002 and 2001, SPR granted the following total shares and related compensation to directors in SPR stock, respectively: 39,370, 18,540, and 14,573 shares, and $150,000, $160,000, and $210,000.

Public Stock Offering

On August 15, 2001, SPR completed a public offering of 23,575,000 shares of its common stock, yielding net proceeds of approximately $340 million, all of which were contributed to NPC as an additional equity investment.

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.

Convertible Notes Issuance

On February 14, 2003, SPR issued and sold $300 million of its 7.25% Convertible Notes due 2010. For additional information regarding this transaction see Note 8 of Notes to Financial Statements, Long-Term Debt. 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.

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 18, Earnings Per Share for a discussion on the effect on the convertible notes and the calculation of basic and diluted EPS.

NOTE 17. 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.

On January 23, 2004, a dividend of $975,000 ($0.4875 per share) was declared on SPPC's preferred stock. The dividend was paid on March 1, 2004, to holders of record as of February 14, 2004.

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	**2003**	2002	**2003**	2002
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 18. EARNINGS PER SHARE (EPS)

The difference, if any, between Basic EPS and Diluted EPS is due to potentially diluted 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 twelve-month periods 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 diluted common shares were determined using the treasury stock method or the "if-converted" method as discussed below.

NOTES TO FINANCIAL STATEMENTS (continued)

FASB EITF Topic D-95, "Effect of Participating Convertible Securities on the Computation of Basic Earnings Per Share" (Topic D-95), requires participating securities that are convertible into common stock be included in the computation of basic earnings per share (EPS) if the effect is dilutive. The Convertible Notes are considered participating securities because the terms of the Convertible Notes include dividend participation rights. Accordingly, the provisions of Topic D-95 are applicable. Further, in computing basic EPS, Topic D-95 provides for the use of the "if-converted" method or the "two-class" method. SPR has elected to apply the "if-converted" method. The effect of the dividend participation rights, under the "if-converted" method, are anti-dilutive for the year ended December 31, 2003, and as such they have not been included in the basic earnings per share calculation. EITF 03-06, "Participating Securities and the Two-Class Method under FASB Statement No. 128" has identified several issues regarding the impact of participating convertible securities on the computation of EPS. Issue 5 addresses whether a convertible participating security would be excluded from the computation of basic EPS if an entity has a net loss from continuing operations. The FASB is scheduled to address this issue at their March 17, 2004 meeting.

The following table outlines the calculation for (EPS):

	2003	2002	2001
BASIC EPS			
NUMERATOR ($000)			
Income/(loss) from continuing operations	**$ (129,375)**	$ (300,851)	$ 32,898
Gain/(loss) on discontinued operations	**$ (7,254)**	$ (1,204)	$ 27,535
Cumulative effect of change in accounting principle	**$ —**	$ (1,566)	$ —
Income/(loss) applicable to common stock	**$ (140,529)**	$ (307,521)	$ 56,733
DENOMINATOR			
Weighted average number of shares outstanding	**115,774,810**	102,126,079	87,542,441
PER-SHARE AMOUNT			
Income/(loss) from continuing operations	**$ (1.12)**	$ (2.95)	$ 0.38
Gain/(loss) on discontinued operations	**$ (0.06)**	$ (0.01)	$ 0.32
Cumulative effect of change in accounting principle	**$ —**	$ (0.02)	$ —
Income/(loss) applicable to common stock	**$ (1.21)**	$ (3.01)	$ 0.65
DILUTED EPS			
NUMERATOR ($000)			
Income/(loss) from continuing operations	**$ (129,375)**	$ (300,851)	$ 32,898
Gain/(loss) on discontinued operations	**$ (7,254)**	$ (1,204)	$ 27,535
Cumulative effect of change in accounting principle	**$ —**	$ (1,566)	$ —
Income/(loss) applicable to common stock	**$ (140,529)**	$ (307,521)	$ 56,733
DENOMINATOR(1)			
Weighted average number of shares outstanding before dilution	**115,774,810**	102,126,079	87,542,441
Stock options	**—**	—	14,021
Executive long-term incentive plan—performance shares(2)	**—**	—	43,693
Executive long-term incentive plan—restricted shares(3)	**—**	—	—
Non-employee Director stock plan	**—**	—	9,355
Employee stock purchase plan	**—**	—	2,862
Dividend participation rights	**—**	—	—
Weighted average number of shares outstanding after dilution(4)	**115,774,810**	102,126,079	87,612,372
PER-SHARE AMOUNT			
Income/(loss) from continuing operations	**$ (1.12)**	$ (2.95)	$ 0.38
Gain/(loss) on discontinued operations	**$ (0.06)**	$ (0.01)	$ 0.32
Cumulative effect of change in accounting principle	**$ —**	$ (0.02)	$ —
Income/(loss) applicable to common stock	**$ (1.21)**	$ (3.01)	$ 0.65

(1) The denominator does not include anti-dilutive shares for the Stock Option Plan and Corporate PIES due to conversion prices being higher than market prices at December 31, 2003. The amounts that would be included in the calculation if the conversion prices were met would be 1.4 million shares for the Stock Option Plan and 17.3 million shares for Corporate PIES.

(2) Plan terminated in 2002.

(3) New plan for 2003.

(4) For the twelve months ended December 31, 2003 and 2002 the weighted average number of shares after dilution excludes shares of 65,836,431 and 32,096, respectively for stock options, executive long-term incentive plan—performance shares, executive long-term incentive plan—restricted shares, non-employee stock plan, employee stock purchase plan, and dividend participation rights as they would be anti-dilutive.

NOTE 19. DISCONTINUED OPERATIONS AND DISPOSAL AND IMPAIRMENT OF LONG-LIVED ASSETS

Effective January 1, 2002, SPR, NPC, and SPPC adopted SFAS No. 144. This statement 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 began negotiations in the second quarter of 2003 to sell e·three. Accordingly, on June 30, 2003, e·three was reported as a discontinued operation. Based on the expected selling price, a pre-tax loss on disposal of $8.9 million was recognized for the six months ended June 30, 2003. On September 26, 2003, the sale of e·three was completed. As a result of the final sales price, an additional pre-tax loss on disposal of $703,787 was recognized for the three months ended September 30, 2003. The operation of e·three was included in the "Other" business segment.

The operation of e·three discussed above was classified as a discontinued operation in the accompanying consolidated statements of operations. Previously issued statements of operations have been restated to reflect discontinued operations reported subsequent to the original issuance date. The revenues associated with the discontinued operations were $1.0 million, $6.4 million, and $16.1 million for the years ended December 31, 2003, 2002, and 2001, respectively.

The assets and liabilities associated with the discontinued operation of e·three are segregated on the consolidated balance sheet at December 31, 2002. The carrying amount of major asset and liability classifications are as follows:

December 31,	2002
Investments and other property, net	$ 9,488
Cash and cash equivalents	1,322
Accounts receivable	111
Materials and supplies	492
Current assets—Other	62
Goodwill	470
Deferred federal income taxes	731
Deferred charges—Other	186
	$12,862
Long-term debt	—
Current maturities of long-term debt	68
Accounts payable	675
Accrued salaries and benefits	30
Deferred credits—Other	14
	$ 787

Sale of Water Business

In June 2001, SPPC closed the sale of its water business to the Truckee Meadows Water Authority (TMWA) for $341 million. SPPC recorded a $25.8 million gain on the sale, net of the refund described below and net of income taxes of $18.2 million. Included in the sale were facilities for water storage, supply, transmission, treatment and distribution, as well as accounts receivable and regulatory assets. Accounts receivable consisted of amounts due from developers for distribution facilities. Regulatory assets consisted primarily of costs incurred in connection with the Truckee River negotiated water settlement. Transfer of hydroelectric facilities included in the contract of sale for an additional $8 million will require action by the CPUC. The sale agreement contemplates a second closing for the hydroelectric facilities to accommodate the CPUC's review of the transaction. See Note 4 of Notes to Financial Statements, Regulatory Actions, for a discussion of California legislative and regulatory developments involving the hydroelectric facilities.

Pursuant to a stipulation entered into in connection with the sale and approved by the PUCN, SPPC was required to hold in trust for refund to customers $21.5 million of the proceeds from the sale. The refund was credited on the electric bills of SPPC's former water customers over a fifteen-month period ending November 2002. Under a service contract with TMWA, SPPC provided customer service and billing services to TMWA until August 2002. SPPC continues to provide meter-reading services under a one-year contract renewable in one-year increments by TMWA through 2008.

Revenue from operations of the water business for the year ended December 31, 2001, was $23 million. The net income from operations of the water business, as shown in the Consolidated Statements of Operations of both SPR and SPPC, includes preferred dividends of $200,000 for the year ended December 31, 2001. These amounts are not included in the revenues and income (loss) from continuing operations shown in the accompanying consolidated statements of operations.

Other Property Disposals

During 2002, the Utilities began pursuing the sale of several non-essential properties. As a result, 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 three years consistent with the accounting treatment directed by the PUCN.

NOTES TO FINANCIAL STATEMENTS (continued)

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 three years consistent with the accounting treatment directed by the PUCN.

Sierra Pacific Communications

In 2000, Sierra Pacific Communications (SPC), a wholly owned subsidiary of SPR, and Touch America (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 between Salt Lake City, Utah, and Sacramento, California.

In September 2002, SPC conveyed its membership interest in STA to Touch America and obtained an indemnity for any liabilities associated with STA, all in exchange for title to several fibers in the line and a $35 million promissory note. On June 19, 2003, citing uncertainty about their liquidity, Touch America Holdings and STA filed for bankruptcy under Chapter 11 of the United States Bankruptcy Code.

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 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 in thousands except per share amounts):

Sierra Pacific Resources

Quarter Ended	March 31, 2003(1)(8)	June 30, 2003(8)	September 30, 2003(8)	December 31, 2003
Operating revenues	$602,810	$ 666,626	$904,877	$614,845
Operating income (loss)	$ 46,376	$ (15,542)	$164,820	$ 52,595(7)
Income (loss) from continuing operations	$ (9,401)(3)	$(210,489)(5)	$109,206(6)	$ (18,691)
Loss from discontinued operations	$ (843)	$ (5,787)	$ (459)	$ (165)
Earnings (loss) applicable to common stock	$(11,219)	$(217,521)	$107,772	$ (19,561)
Earnings (Loss) Per Share—Basic and Diluted:				
From continuing operations	$ (0.08)	$ (1.80)	$ 0.40	$ (0.16)
From discontinued operations	$ (0.01)	$ (0.05)	$ —	$ —
Earnings (loss) applicable to common stock	$ (0.10)	$ (1.85)	$ 0.39	$ (0.17)

Quarter Ended	March 31, 2002	June 30, 2002	September 30, 2002	December 31, 2002
Operating revenues	$ 636,934	$700,524	$1,017,371	$630,475
Operating income (loss)	$(230,638)(2)	$ 20,415(4)	$ 143,272	$ 34,902
Income (loss) from continuing operations	$(302,769)	$ (40,350)	$ 80,363	$ (38,095)
(Loss) from discontinued operations	$(172)	$ (591)	$ (14)	$ (427)
Earnings (loss) applicable to common stock	$(305,482)	$ (41,916)	$ 79,374	$ (39,497)
Earnings (Loss) Per Share—Basic and Diluted:				
From continuing operations	$ (2.97)	$ (0.40)	$ 0.78	$ (0.39)
From discontinued operations	$ —	$ (0.01)	$ —	$ —
Cumulative effect of change in accounting principle	$ (0.01)	$ —	$ —	$ —
Earnings (loss) applicable to common stock	$ (2.98)	$ (0.41)	$ 0.78	$ (0.39)

(1) *The amounts previously reported in the March 2003 10Q differ from the amounts currently reported due to 1st quarter revisions to reflect the discontinued operations presentation. Amounts were revised as shown in the tables below.*

(2) *Reflects the write-off of approximately $465 million of deferred energy costs and related carrying charges as a result of the PUCN decision in NPC's deferred energy rate case. See Note 4, Regulatory Actions.*

(3) *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 11, Derivatives and Hedging Activities.*

(4) *Operating results were negatively affected by the write-off of $53 million of SPPC's disallowed energy costs.*

(5) *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 discussed in Note 11, Derivatives and Hedging Activities and loss due to the recognition of asset impairments of $33 million.*

(6) *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 11, Derivatives and Hedging Activities and higher interest cost that included the recognition of $40.2 million in interest as a result of the Bankruptcy Court Judgment regarding Enron. See Note 15 of Notes to Financial Statements, Commitments and Contingencies.*

(7) *In the fourth quarter of 2003, SPR recognized charges of approximately $6.3 million (pretax) 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.*

(8) *On February 14, 2003, SPR issued and sold $300 million of its 7.25% Convertible Notes due 2010 (see Note 8, Long-Term Debt). In connection with these Notes, the conversion option, which was treated as a cash-settled written-call option, was separated from the debt and accounted for separately as a derivative instrument. The change in the fair value of the option was recognized during 2003 in SPR's financial statements as an unrealized gain/loss on the derivative instrument. SPR also recorded deferred tax expense or benefit during the first three quarters of 2003, on the unrealized gain/loss, based on its belief that the change was a temporary difference. Additionally, as a result of the bifurcation of the conversion option from the Notes, the carrying value of the Convertible Notes at issuance was approximately $228 million with an effective interest rate of 12.5%. SPR began accreting the difference between the stated value of the Notes ($300 million) and the carrying value to interest expense on a monthly basis over the life of the issuance. SPR recorded current tax expense on the accretion of the interest expense.*

NOTES TO FINANCIAL STATEMENTS (continued)

Subsequent to the issuance of its interim financial statements for the first three quarters of 2003, SPR determined that the change in the fair value of the conversion option and the accretion expense of the debt discount resulting from the option at issuance date represent permanent differences and that SPR should not have recognized income taxes associated with these items.

As a result, the quarterly information presented herein has been restated from the amounts reported with SPR's interim financial statements for the first three quarters of 2003 to remove $5.6 million of deferred tax expense, $43.2 million of deferred tax benefit, and $21.5 million of deferred tax expense associated with the change in the fair value of the option for the quarters ended March 31, 2003, June 30, 2003, and September 30, 2003, respectively and has removed $0.3 million, $0.6 million, and $0.6 million of current tax expense associated with the accretion expense related to the conversion option for the quarters ended March 31, 2003, June 30, 2003, and September 30, 2003 respectively. See revised quarterly data below.

	Originally Reported March 31, 2003	Adjustment for Discontinued Operations	Adjustment for Convertible Notes	Revised March 31, 2003
Operating revenues	$602,962	$ (152)	$ —	$602,810
Operating income (loss)	$ 45,797	$ 874	$ (295)	$ 46,376
Income (loss) from continuing operations	$(15,523)	$ 843	$5,279	$ (9,401)
Loss from discontinued operations	$ —	$ (843)	$ —	$ (843)
Earnings (loss) applicable to common shareholders	$(16,498)	$ —	$5,279	$(11,219)
Earnings (Loss) Per Share—Basic and Diluted:				
From continuing operations	$ (0.14)	$ 0.01	$ 0.05	$ (0.08)
From discontinued operations	$ —	$(0.01)	$ —	$ (0.01)
Earnings (loss) applicable to common shareholders	$ (0.15)	$ —	$ 0.05	$ (0.10)

	Originally Reported June 30, 2003	Adjustment for Convertible Notes	Revised June 30, 2003
Operating revenues	$ 666,626	$ —	$ 666,626
Operating income (loss)	$ (14,937)	$ (605)	$ (15,542)
Loss from continuing operations	$(166,658)	$(43,831)	$(210,489)
Loss from discontinued operations	$ (5,787)	$ —	$ (5,787)
Earnings (loss) applicable to common shareholders	$(173,420)	$(43,831)	$(217,251)
Earnings (Loss) Per Share—Basic and Diluted:			
From continuing operations	$ (1.42)	$ (0.37)	$ (1.80)
From discontinued operations	$ (0.05)	$ —	$ (0.05)
Earnings (loss) applicable to common shareholders	$ (1.48)	$ (0.37)	$ (1.85)

	Originally Reported September 30, 2003	Adjustment for Convertible Notes	Revised September 30, 2003
Operating revenues	$904,877	$ —	$904,877
Operating income (loss)	$165,444	$ (624)	$164,820
Income from continuing operations	$ 88,301	$20,905	$109,206
Loss from discontinued operations	$ (459)	$ —	$ (459)
Earnings (loss) applicable to common shareholders	$ 86,867	$20,905	$107,772
Earnings (Deficit) Per Share—Basic and Diluted:			
From continuing operations	$ 0.29	$ 0.11	$ 0.40
From discontinued operations	$ —	$ —	$ —
Earnings (loss) applicable to common shareholders	$ 0.28	$ 0.11	$ 0.39

Nevada Power

Quarter Ended	March 31, 2003	June 30, 2003	September 30, 2003	December 31, 2003
Operating revenues	**$331,652**	**$425,512**	**$639,661**	**$359,321**
Operating income (loss)	**$ 17,413**	**$ 10,484(2)**	**$127,737**	**$ 28,099**
NET INCOME (LOSS)	**$ (15,246)**	**$ (22,192)**	**$ 62,524(3)**	**$ (5,809)**

Quarter Ended	March 31, 2002	June 30, 2002	September 30, 2002	December 31, 2002
Operating revenues	$ 356,272	$477,059	$712,536	$355,167
Operating income (loss)	$(260,759)(1)	$ 30,162	$109,183	$ 17,411
NET INCOME (LOSS)	$(300,984)	$ 5,655	$ 79,304	$ (19,045)

(1) Reflects the write-off of approximately $465 million of deferred energy costs and related carrying charges as a result of the PUCN decision in NPC's deferred energy rate case. See Note 4, Regulatory Actions.

(2) Reflects the write-off of $46 million in May 2003 of disallowed deferred energy costs.

(3) Reflects the charge of $27.8 million of interest cost as a result of the Bankruptcy Court Judgment regarding Enron as discussed in Note 15, Commitments and Contingencies.

Sierra Pacific Power

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)(2)**	**$ 32,588**	**$ 20,208**
NET INCOME (LOSS)	**$ 3,998**	**$ (27,955)**	**$ (317)(3)**	**$ 999**
Earnings (loss) applicable to common stock	**$ 3,023**	**$ (28,930)**	**$ (1,292)**	**$ 24**

Quarter Ended	March 31, 2002	June 30, 2002	September 30, 2002	December 31, 2002
Operating revenues	$279,837	$222,668	$304,193	$274,336
Operating income (loss)	$ 24,934	$ (14,818)(1)	$ 30,021	$ 15,155
NET INCOME (LOSS)	$ 10,944	$ (33,951)	$ 13,543	$ (4,504)
Earnings (loss) applicable to common stock	$ 9,969	$ (34,926)	$ 12,568	$ (5,479)

(1) Operating results were negatively affected by the write-off of $53 million of SPPC's disallowed energy costs.

(2) Reflects the write-off of $45 million in June 2003 of disallowed deferred energy costs.

(3) Reflects the charge of $12.4 million of interest costs as a result of the Bankruptcy Court Judgment regarding Enron as discussed in Note 15, Commitments and Contingencies.

SHAREHOLDER INFORMATION

CORPORATE DOCUMENTS

The SEC Annual Report on Form 10-K and 10-Year Statistical Report are available free of charge by written request to:

Shareholder Relations
Sierra Pacific Resources
P.O. Box 30150
Reno, Nevada 89520-3150

INDEPENDENT ACCOUNTANT

Deloitte & Touche LLP
Reno, Nevada

ANALYST CONTACT

Vicki Erickson
Sierra Pacific Resources
Investor Relations
P.O. Box 30150
Reno, Nevada 89520-3150
(775) 834-5646

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 Harrah's Reno Hotel and Casino, 219 N. Center Street, Reno, Nevada, at 10 a.m. (PDT) on Monday, May 3, 2004.

2003 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 2003 and 2002 are as follows:

	Dividends Paid Per Share	High	Low
2003			
First Quarter	**$.000**	**$ 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**
2002			
First Quarter	$.200	$16.850	$14.710
Second Quarter	.000	10.500	5.590
Third Quarter	.000	8.500	5.270
Fourth Quarter	.000	7.020	4.650

SIERRA PACIFIC RESOURCES—SENIOR OFFICERS

( ) years of utility experience

Walter M. Higgins
Chairman, President and Chief Executive Officer, SPR; Chief Executive Officer, NPC/SPPC (27)

Jeffrey L. Ceccarelli
President, SPPC (32)

Donald L. "Pat" Shalmy
President, NPC (*)

Michael W. Yackira
Executive Vice President and Chief Financial Officer, SPR/NPC/SPPC (17)

Ernest E. East
Vice President, General Counsel and Corporate Secretary, SPR/NPC/SPPC (*)

Roberto R. Denis
Vice President, Energy Supply, NPC/SPPC (31)

Victor H. Peña
Senior Vice President and Chief Administrative Officer, SPR/NPC/SPPC (13)

SPR: Sierra Pacific Resources
NPC: Nevada Power Company
SPPC: Sierra Pacific Power Company

**Messrs. Shalmy and East joined the company in July 2002 and January 2004, respectively. Mr. Shalmy has 35 years of administrative management experience; Mr. East has been general counsel for several major corporations and has more than 30 years experience handling legal affairs and regulatory issues.*

SIERRA PACIFIC RESOURCES—BOARD OF DIRECTORS

( ) years of board service

Mary Lee Coleman
President of Coleman Enterprises, a developer of shopping centers and industrial parks. (24)

Krestine M. Corbin
President and Chief Executive Officer of Sierra Machinery, Inc., a manufacturer of roller burnishing heads and machines. (15)

Theodore J. Day
Senior Partner of Hale, Day, Gallagher Company, a Nevada-based real estate brokerage and investment firm. (17)

James R. Donnelley
Partner, Stet and Query, Ltd., a family-owned investment company; Director of Pacific Magazines & Printing, Ltd.; retired Vice Chairman of the Board, R.R. Donnelley & Sons. (17)

Jerry E. Herbst
Chief Executive Officer of Terrible Herbst, Inc., a large chain of family-owned service stations and related businesses; partner in Coast Resorts, a hotel-gaming company. (14)

Walter M. Higgins
Chairman, President and Chief Executive Officer, Sierra Pacific Resources; Director and Chief Executive Officer of Nevada Power and Sierra Pacific Power. (9)

John F. O'Reilly
Chairman and Chief Executive Officer of the law firm of O'Reilly and Ferrario; Chairman and Chief Executive Officer and/or a Board member of various family-owned business entities. (9)

Clyde T. Turner
Chairman and Chief Executive Officer of Turner Investments, a general purpose investment company, and Spectrum Companies, a special purpose real estate development company; retired Chairman and Chief Executive Officer of The Mandalay Bay Group, a hotel-gaming company. (2)

Designed by Curran & Connors, Inc. / www.curran-connors.com

SIERRA PACIFIC RESOURCES
P.O. Box 30150
Reno, NV 89520-3150
www.sierrapacificresources.com